BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	**DOCKET NO. 990001-EI**
Fuel and purchased power cost recovery clause and generating performance incentive factor.	

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Pages 696 through 784

PROCEEDINGS:	**HEARING**
BEFORE:	COMMISSIONER J. TERRY DEASON COMMISSIONER SUSAN F. CLARK COMMISSIONER E. LEON JACOBS, Jr.
DATE:	**Tuesday, November 23, 1999**
TIME:	Commenced at 9:00 a.m. Concluded at 4:48 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JOY KELLY, CSR, RPR Chief, Bureau of Reporting FPSC Commission Reporter
APPEARANCES:	(As heretofore mentioned.)

DOCUMENT NUMBER-DATE
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I N D E X

ISSUES	PAGE
Stipulated issues	697
Issue 9 - 13	702
Issue 11 & 12	704
Issue 12 & 13	715
Issue 16A, 16B, 16C, 17D, 17E	767
Issue 19B, 19E, 19D, 19H, 19I, 19J	771
Issue 19K-O	780
Issue 31	780

P R O C E E D I N G S

(Transcript continues in sequence from Volume 4.)

COMMISSIONER DEASON: Call the hearing back to order.

MR. KEATING: Commissioners, at this point we believe it would be appropriate to vote approval of the stipulated issues. Those issues are Issues 1, 5, 6, 8, 17A, 17B, 17C, 18A, 18B, 19A, 19C, 19F, 19G, 20A, 20B, 20C, 21, 22, 23, 24, now 25 and 26. I believe that those are shown as stipulated as to all of the utilities except Florida Power & Light. These are all of the issues that are shown as stipulated in the Prehearing Order.

MR. STONE: May I ask for clarification from the Staff as to -- I thought it showed on Issues 2 and 3 they were stipulated as to Gulf.

COMMISSIONER CLARK: Well, they are fallout issues, right?

MR. STONE: I just thought I saw agreement on the numbers.

MR. KEATING: I think we do have an agreement on the numbers and the reason we aren't showing them as stipulated is because there is a fallout from resolution of other issues that remain.

MR. STONE: My confusion is I'm not sure that the issues that remain as to Gulf have any impact on Issues 2 and 3.

MR. KEATING: I'm sorry, Gulf is stipulated as to Issues 2 and 3. Staff can stipulate as to Gulf's positions on Issues 2 and 3. I'm not aware if FIPUG or Public Counsel can also stipulate on those issues.

COMMISSIONER DEASON: Well, we'll address all the other issues and whatever falls out falls out.

And you're saying that Issues 25 and 26 are stipulated except for FPL.

MR. KEATING: That's correct.

COMMISSIONER DEASON: And why is it FPL is not included in the stipulation?

MR. BOHRMANN: The issues on the energy and capacity payments --

COMMISSIONER DEASON: Is your microphone on? Get a little closer to it, please.

MR. BOHRMANN: The issue of the energy and capacity payments to Cedar Bay, which the Commission decided to defer until a later time, affects those issues. So we don't have a decision from the Commission, so that's the reason why.

COMMISSIONER DEASON: Nevertheless, we're

going to have to determine factors to be applied starting in January.

MR. BOHRMANN: Yes, that is correct.

COMMISSIONER DEASON: And that should be the outcome of the decision, understanding that there are yet decisions to come in the future and there will be true-ups one way or the other to make parties whole.

MR. BOHRMANN: Right. As far as I know, that is the only outstanding issue as it refers to FPL's capacity on Issues 25 and 26.

COMMISSIONER DEASON: Okay. Staff, how do you wish to proceed from this point? Do you want us to address all of the stipulated issues that you just identified, with the exception of 25 and 26 as it relates to FPL?

MR. KEATING: Yes. We can do them all at once if you wish or one by one.

COMMISSIONER CLARK: Mr. Chairman, I would make a motion that we approve the stipulations on those issues identified by Staff, and then I'll make a separate motion on 25 and 26.

COMMISSIONER DEASON: Is there a second to that?

COMMISSIONER JACOBS: Yes. Let me get the first -- up through Issue 14 -- I was writing as you

went but I missed some of it. Issue 1.

COMMISSIONER CLARK: I think 1, 5, 6, 8, 17, A through C, 18A and B. 19A, 19C, 19F, 19G, 20A through C. 21, 22, 23, 24.

COMMISSIONER JACOBS: Okay. I'll second it.

COMMISSIONER DEASON: It's been moved and seconded. Show the Commission approves the stipulated issues unanimously.

COMMISSIONER CLARK: With respect to Issue 25 and 26, do I understand that you are in agreement for the amounts if Cedar Bay is included as to FPL?

MR. BOHRMANN: That would be correct.

COMMISSIONER CLARK: All right. I would be willing to move Issue 25 and 26, including the amounts identified by Florida Power & Light, with the understanding that they are going to be revisited at a later time and appropriate adjustments made.

COMMISSIONER JACOBS: I'll second that. Do we have a time frame? It doesn't matter, I guess. This will be the fact that it goes in. When we come back with a revision, they'll just revise the rate at that time or just the next cycle around?

MR. KEATING: The factor, at least as issues -- as it is affected by the Cedar Bay issue,

will remain the same and go into effect on January 1st. I believe that was the Commission's decision.

COMMISSIONER JACOBS: Okay.

COMMISSIONER DEASON: We did not require a recalculation so that the numbers as submitted -- as long as Staff agreed that those numbers were calculated correctly, that we could base the factor on that with the understanding that there was going to be a final disposition of the issue, and there will be -- may necessarily be a true-up with interest and that sort of thing in one direction or another.

MR. KEATING: That's correct.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Okay. Been moved and seconded. Show, then, that that motion carries for Issues 25 and 26 as relates to FPL.

COMMISSIONER CLARK: And approve the stipulations with respect to the other ones.

COMMISSIONER DEASON: Yes. So that should address all of the stipulated issues as identified by Staff.

MR. KEATING: Commissioners, there's one other, I suppose, stipulation that can be addressed now. We are stipulated with Florida Public Utilities

Company on Issues one, 2, 3, 4, and 7.

COMMISSIONER JACOBS: With respect to Florida Public Utilities, I would move that stipulation. Move we approve that stipulation.

COMMISSIONER DEASON: Let's deal with substantive issues now and then we'll go back and do all the fallouts. Those are fallouts for Florida Public, correct? I just don't want to try to keep up which issues were decided for which companies. We'll just deal with the issues, if that's all right.

COMMISSIONER CLARK: Issue 1 we've already approved. It would be 2, 3 and 4.

COMMISSIONER DEASON: Right. And what I'm saying is let's wait and do the fallout issues when we've got all of the issues decided for all of the companies. Can we do that? I'm just trying to do it easily and make my bookkeeping as simple as possible.

I believe what we need to do at this point is move to the non-stipulated issues, the non-fallout issues. Address those. And if Staff's got a suggested order on those, that will be fine.

MR. KEATING: I would suggest that we take up Issues 9 through 13 first, and then move to company-specific issues.

COMMISSIONER DEASON: Okay. We're then on

Issue 9.

MS. DRAPER: Commissioners, Staff raised Issue 9 and 10 because we became aware during the past year that Power & Light, Power Corp, TECO and Gulf treat the revenues received from nonbroker nonfirm wholesale energy sales differently. Specifically, the differences involve the treatment of generational generated gains and transmission revenues associated with those sales.

Issue 9 deals with the transmission revenues. Pursuant to FERC Order 888, utilities are required to separately identify and charge a transmission component for all wholesale sales, including these types of sales. Prior to 888, utilities only charged an energy charge and a transmission power was free, if you like.

Power Corp currently treats the transmission revenues as a credit to operating revenues; Power and Light as a credit to the capacity clause, and Gulf and TECO as a credit to the fuel clause.

Staff recommends that the transmission revenues should be credited to the retail ratepayers for the capacity cost recovery clause. The capacity cost recovery clause allocates cost-based based on each class's contribution to peak demand. This

allocation method conforms with the method used to allocate transmission costs in a base rate proceeding.

Power Corp's current treatment to credit those revenues to operating revenues does not provide immediate benefits to retail ratepayers in the absence of the rate case. Crediting those revenues to the capacity clause will provide immediate reduction to retail rates.

Now, Power Corp revised its position on this issue stating it agrees with Staff if the Commission extends the 20% gain to all economy sales.

I guess at this point I can say I'm happy that Power Corp will agree with Staff on this issue, but if the gains -- 20% gains should be applied to all economy sales, that's something the Commission will address in Issues 11 and 12.

COMMISSIONER CLARK: Let me ask a question. Did I understand Mr. Howell as saying that they had recommended that it be to general revenue, but that we had already decided not to do that. And if that were the case, it was immaterial to them whether it was fuel or capacity?

MS. DRAPER: Yes.

Another issue, Power Corp also thrust in this issue the separation factor that we apply to

transmission related revenues. Separation factors are used to divide the costs or revenues between the retail and wholesale jurisdictions. And the transmission related costs are being separated based on a demand responsibility.

Florida Power Corporation believes it is appropriate to separate revenues from transmission between the two jurisdictions based on its currently effective transmission separation factor.

Power Corp's transmission-related separation factor results in the allocation of about 30% of its transmission related costs and revenues to the wholesale jurisdiction. This compares with an allocation of less than 3% if the generation related energy allocation is used.

Staff believes that given the disparity between the separation factors, Power Corp should be permitted to use its transmission allocator for these revenues.

That concludes my summary on Issue 9.

COMMISSIONER CLARK: So it's Staff's recommendation that the transmission revenues be a credit to -- that the revenue go through the capacity clause.

MS. DRAPER: That's correct.

COMMISSIONER CLARK: And for Florida Power Corporation, they should be allowed to do a separation based on their investment in transmission separation.

MS. DRAPER: It's based on their transmission separation factor which is substantially different from the generation separation.

COMMISSIONER CLARK: That would be my motion, Mr. Chairman.

COMMISSIONER DEASON: There is a motion. Is there a second?

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Moved and seconded. Show that motion carries unanimously. That disposes of Issue 9.

MS. DRAPER: Issue 10 deals with the generation-related gains.

Currently Power and Light and Power Corp credit those gains to the capacity clause while TECO and Gulf credit the fuel clause with those revenues.

Staff recommends that the generation-related gain on nonfirm nonbroker wholesale energy sales be credited to the ratepayers through the fuel clause. This results in the allocation of the benefits of these sales on an energy basis.

We heard testimony that utilities do not

plan or build capacity to make this nonfirm sales, and these sales contain no capacity-related cost component. It would, therefore, be inappropriate to credit those revenues to the capacity clause.

Now, Power Corp's witness stated that some of the sales do have a identifiable capacity component, so at this point I would suggest that to the extent that there is an identifiable capacity component in those sales, that gain should be flowed through the capacity clause.

COMMISSIONER DEASON: Is the component applicable to capacity? Can that be readily identified?

MR. WHEELER: I believe Witness Wieland did indicate that some of these transactions we're talking about, in other words, nonseparated-type transactions, do have some level of firmness and had a capacity or a reservation charge associated with them. Typically when you're talking about these nonfirm-type transactions, it's strictly an energy charge and that there is no capacity component.

We just want to emphasize that for types of sales that do have a identifiable component related to capacity -- in other words, a capacity charge versus an energy charge -- that we believe that the capacity

cost recovery clause was designed to flow those types of revenues back to the ratepayers.

COMMISSIONER DEASON: I guess I have a question with Staff's -- with your basic premise. And that is that these amounts get flowed through the fuel clause based upon a fuel basis and not on a capacity basis. You say the reason is because there -- utilities do not plan and build for this capacity. That if they are able to make these transactions. It's not because they built and planned capacity to serve these transactions, it's just that any given time the economics are such that these actions can take place. Is that correct?

MS. DRAPER: That's correct.

COMMISSIONER DEASON: Nevertheless, there has to be capacity there to serve the demand, or to serve the energy required under these transactions. And someone is paying for that capacity in their rates.

MR. WHEELER: Correct. But I guess the Staff's perspective is that when you're making these kinds of economy sales, you're not -- let me back up.

Plant is built to serve the peaks. When you're making an economy sale, you're obviously not in a peak situation. You've got excess capacity that you

can make available because the generation costs are less than the utility that's buying the energy. So really it's just a matter of -- I understand it's a difficult distinction to make. But I think the fact that there are no capacity costs related to the sale would dictate an energy-type allocation as opposed to a peak demand-type allocation. I don't know if that helped any.

COMMISSIONER JACOBS: That's the premise of these transactions, is that it is excess, right? That's one of the premises of these transactions, is that there are excesses.

MS. DRAPER: Additionally, I'd like to point out that when utilities make nonfirm wholesale purchases, they recover the -- credit the gains of those purchases through the fuel clause.

MR. WHEELER: They recover the cost when they make those purchases through fuel on an energy basis. So you could argue that in order to have symmetry, you would have the same treatment when you're selling.

COMMISSIONER DEASON: Is there differing treatment by the utilities in this regard?

MS. DRAPER: Yes. Power & Light and Florida Power Corp used the capacity clause and TECO and Gulf,

the fuel clause.

MR. WHEELER: Until recently, three of the four were flowing it through fuel. Recently Power Corp switched from capacity to fuel effective, I believe -- is it --

MS. DRAPER: January 1, '99.

MR. WHEELER: January 1, '99.

COMMISSIONER DEASON: From capacity to fuel.

MR. WHEELER: No, I'm sorry. The other way.

MS. DRAPER: From fuel to capacity. Previously used the fuel clause.

COMMISSIONER DEASON: What did they state was the reason for that, to switch from fuel to capacity?

MS. DRAPER: The first reason was stated because Power and Light does it that way. And the second reason -- it didn't seem like it was a --

MR. WHEELER: There was some testimony that these served as a contribution to the fixed cost; that the ratepayers were supporting the plant, the fixed cost of the plants. And that any access revenue should be credited on that basis.

COMMISSIONER DEASON: I guess that's the point I was trying to make. It seems to me that when a utility does plan and build capacity, I agree, it's

to serve the peak. And the people that contribute to the peak are the ones most likely to be paying for that plant. But when that plant is not needed for the peak and can be utilized to serve someone else's load, economically shouldn't the people that are paying most for it through the peak allocator be the ones that get the benefit when they don't need it at that time and it's being sold to someone else? If you allocate it on a capacity basis, those are the customers then that are then getting the benefit. What's wrong with that -- with that analysis?

MR. WHEELER: Again, I'd have to go back to the -- when the capacity cost recovery clause was first created it was to allow utilities to recover the capacity-related cost-related costs of plant that they had added subsequent to their last rate case because they -- to remove that disincentive for them to purchase power on a firm basis. And the order in that docket also indicated that to the extent they were capacity-related revenues, they could also flow through the clause to serve to reduce that obligation to pay the capacity costs.

Again, since these types of transactions are strictly an energy-based transaction that involved no commitment of plant, they are recallable, if the plant

is needed to serve the peak load of the utility, it can be recalled. In that sense, in my mind, they are an energy-related type revenue. They are a product of the utility being able to make an energy sale as opposed to a capacity commitment.

COMMISSIONER DEASON: The sale would never take place unless you had the capacity of the plant there.

MR. WHEELER: Right. But at the time you're making the sale you're not --

COMMISSIONER CLARK: Did I understand the witnesses, though, to say that the only way the economy sales are made is it is based on the fact both the selling and the buying -- and the buying entity have capacity. It's just that it's cheaper to purchase the energy.

MR. WHEELER: That's correct.

COMMISSIONER CLARK: Mr. Chairman, I would recommend that we approve Staff on Issue 10. And that would -- let me just be clear. That simply is to flow through the generated -- generation-related gain on nonseparated wholesale energy sales not made through the energy broker network would be credited back to the fuel clause. My motion does not include the split. I think we should deal with that. I guess

it's Issue 11.

MR. WHEELER: That's correct. We want to make clear that these issues are pretty much divorced from the decision as to what the incentive will apply to. It's really a clause treatment question we're speaking to here.

COMMISSIONER JACOBS: I'm not sure if this applies here, but there was a discussion at one point in the debate about capacity that was obtained ostensibly and put on the retail -- I'm sorry, on residential and retail, but really, at least for the short term, was going to be primarily used to make these kind of sales, the economy sales.

MR. WHEELER: Right. These are short term nonfirm-type transactions. When I say "nonfirm" I mean they are generally recallable. In other words, if the selling utility discovers they need that energy to serve their own native load, they can recall that sale. They can cancel that sale. So they don't plan to serve these types of sales when they do generation planning in terms of meeting the peak demands.

COMMISSIONER JACOBS: But my question is, is there some kind of hidden incentive in the way things are done presently to do that? To go out and try and get more capacity to make these kind of sales?

MR. WHEELER: I'm not sure I understand.

COMMISSIONER JACOBS: If the trend is that you have a tight market and you see these recurring charges every summer out of region, are we doing something to incentivize those --

COMMISSIONER CLARK: Building capacity, so you can -- and have it in the retail rate so you can sell it as economy sales.

COMMISSIONER JACOBS: Yeah.

MR. WHEELER: I guess that's a possibility. Presumably that would be handled through the need determination process in terms of the utility's plan to meet firm peak demand. They don't plan to serve economy. So presumably if you plan properly to meet your peaks, you're not going to building excess.

COMMISSIONER JACOBS: I understand. My question had to do in this process, do we make sure that we have adequate protections and safeguards and we're giving proper incentives to make sure that that conduct is not encouraged.

MR. WHEELER: Well, at this point I don't think we're dealing with the incentive side of the picture. Right now we're just talking about for those gains that we do flow back, how do we flow them back. So really the issue in terms of incentives would come

in Issues 12 and 13.

COMMISSIONER CLARK: Mr. Chairman, I think I made a motion but I really didn't address all of Staff's recommendation because they had indicated that it should go to the capacity clause to the extent there is a capacity component in the economy sale. I guess, I'm not -- it's not clear to me why there would be a capacity component in the sale, but --

MR. WHEELER: Typically there would not be. I just want to make clear that the position Staff is taking is that for those types of sales that do have a capacity component, those revenues should be flowed back through the capacity cost recovery clause. That's basically what the clause, or part of the reason the clause was created. I just don't want to -- I want to make sure that for those types of transactions, whatever type they are, they have an identifiable capacity component; that that component would go through capacity.

COMMISSIONER JACOBS: I'll second the motion.

COMMISSIONER DEASON: Let me ask a question. Just because a part of it is identified as capacity, it still doesn't change the fact that the plant isn't built to meet the other person's capacity needs.

MR. WHEELER: Again, to the extent that there is a capacity or reservation charge, I think you would no longer call that a nonfirm sale. It would have a degree of firmness to it.

COMMISSIONER DEASON: Nevertheless, there's been a motion and a second.

COMMISSIONER CLARK: There has been a motion. But I guess the problem is we've sort of indicated for economy sales that are not on the broker it would be the fuel costs. And it strikes me that if there is a capacity element in there, it's no longer an economy sale. It's something else.

MR. WHEELER: Yes. I would agree.

The only reason we have that caveat is that Mr. Wieland, in his testimony, mentioned that there are some transactions that do have some element of a reservation or a capacity-type fixed charge. That's the only reason --

COMMISSIONER CLARK: I guess I'm willing to move that the economy sales should be credited to the fuel clause. To the extent there are things that are labeled economy sales that have a capacity component, I would move that the capacity component go through the capacity clause. But I would like Staff to investigate, and get a handle on, what these sort of

hybrid sales are.

MR. WHEELER: Okay. We could do that.

MR. BALLINGER: Commissioner Clark, I think that's one of the problems with Issue 11 is defining economy sales. And I think that's what you're struggling with here.

COMMISSIONER DEASON: We do have a motion and a second. Show then that approved unanimously. And that addresses Issue 10. Issue 11.

MR. BALLINGER: Commissioners, Issue 11 deals with the Staff's recommendation to remove the 20% incentive for economy broker sales. We're not sure what we need to call them. And I think I need to get clear on a definition first.

Let me go back and state that this problem arose a couple of years ago when we found out -- when FERC Order 888 required unbundling of transmission revenues for economy sales, we found out that the four IOUs interpreted that.

COMMISSIONER CLARK: The FERC required unbundling for all sales.

MR. BALLINGER: But specifically for economy. And the four utilities we found were doing it differently, and, therefore, affected the gains on the economy sales, and, therefore, affected the 20%.

So what we had at that time was disparate treatment among the four utilities. That raised Staff's concern. We started investigating this a little bit more.

We found out further that an interpretation of what is an economy sale was different among the utilities. We found Florida Power Corp and Florida Power & Light viewed that order that came out in 1984 as economy sales are those split-the-savings sales that you did over the broker network within Florida, EBN network. Tampa Electric Company interpreted that order to mean any split-the-savings sale, whether it be over the broker or outside the broker, just so the methodology was split-the-savings.

Gulf Power interpreted that order to mean any economy sale, which means if I have a willing buyer and a willing seller, and it's -- I'm not sure whether they need capacity to backup the purchase or not, if it's made at a sale, it's an economy sale and they take 20% on market-based and cost-based sales. So we had a whole spectrum of what is an economy sale. It's never really been cleared up. I think this is a good time to do that.

That's one of the reasons Staff has recommended that you remove this 20% gain incentive

and flow all of the credit back to the retail customers. That way it doesn't matter what you call an economy sale. All nonseparated sales that are made on a short-term basis, all of the revenues flow back to the ratepayers. We don't have this gaming of a system anymore of a 20% going back to the stockholders. We don't have to worry about what the definition means.

We also found out, at least at this hearing, I was unaware until today that Tampa Electric is also taking 20% of transmission revenues on the gains. In other words, they include those as the gains on these economy sales. Albeit, they are split-the-savings, but they then would take the transmission revenues and also claim 20% to their stockholders.

COMMISSIONER CLARK: That's what you would be doing if they were bundled.

MR. BALLINGER: Not necessarily. The original broker system had zero transmission costs in it. So when the FERC Order 888 came out, that was one of Staff's arguments is that you're not having an incremental cost of transmission added to a sale, you're just renaming it. You're calling part of the gain transmission and then trying to claim 20% of it. My understanding is Tampa Electric is only

splitting --

COMMISSIONER CLARK: Tom, let me interrupt you for a minute.

If they required them to split some costs out that cost -- and label it "transmission," then transmission costs were part of the bundled rate.

MR. BALLINGER: That's an argument we had; last year in the fuel hearing about what that unbundling actually meant. I think Staff and the Commission agreed that it was -- the original broker that split-the-savings was generation only. If you had a separate transmission charge, that is unbundled and charged separately and flowed through the clause.

COMMISSIONER CLARK: When it was bundled, was it part of the broker system?

MR. BALLINGER: It was bundled but it was priced at zero.

COMMISSIONER JACOBS: How did the other charges -- you said there was a transmission charge that occurred outside of the broker system, though. Did I understand you to say that?

MR. BALLINGER: For transactions outside of the broker?

COMMISSIONER JACOBS: No, no. The first question was when the transactions were bundled, was

there a transmission cost.

MR. BALLINGER: No. It was assumed to be zero. You're talking about originally prior to FERC 888.

COMMISSIONER JACOBS: Right.

MR. BALLINGER: Okay.

COMMISSIONER CLARK: But when FERC Order 888 came out, then the prices quoted were broken out.

MR. BALLINGER: No, they weren't. If they were, you should have seen the exact same -- you would have seen a little bit higher price on the sell side, if you actually added a transmission component. That's water under the bridge. The Commission has decided how to treat those transmission revenues. What I'm trying to get to --

COMMISSIONER CLARK: How have we decided to treat them?

MR. BALLINGER: My understanding is that the last fuel hearing we had an issue about what do you do with transmission revenues for sales over the broker network only; that was a specific issue. The Commission ruled to flow those back through the fuel clause; is that correct?

COMMISSIONER CLARK: All right. Just like we've done today.

MR. BALLINGER: Today you flowed them through the capacity clause in Issue 9 for nonbroker sales. The reason being, I think, is because the original broker system was set up where transmission was zero; it was all generation anyway, and we're trying to keep that system pure of split-the-savings. It's confusing. I understand.

Other things we're recommending to get rid of the 20% is things that have evolved over time, since 1984. I believe in Ms. Harlow's testimony she pointed out that the market has changed since 1984 when the 20% was first adopted. Today we have more pressure at the retail level for utilities to keep their rates low. With changes in technology and natural gas prices, industrial customers have a great leverage tool for self-generation. Utilities are scraping every nickel and dime they can to keep their rates as low as possible. Off-system sales and purchases are one of those tools.

Back in 1984 making off-system sales was kind of a peripheral function of the dispatcher. It was kind of like, "Okay. I have got some time. I've got some excess capacity. Let me call up Joe over here and see if he needs some." Today it's dedicated personnel, 10, 12 people that do nothing but around

the clock are on the phone beating the bushes across the nation looking for opportunity sales. So that part of the business has changed. Those expenses that we heard today are included in surveillance reports, so it's affecting the company's earnings. And presumably if they ever came in for a rate case, it would be recovered in base rates.

We've also seen a decline in the broker activity, Florida Broker activity, or split-the-savings activity. The main reason being is that is a very restrictive mechanism for making a sale. It's a fixed mathematical function. It's A plus B divided by 2. We've seen utilities going more towards marketplace or negotiated pricing because it adds more flexibility. You can structure it for two hours, three hours a day --

COMMISSIONER CLARK: Let me ask a question on that. Can FPL and FPC make marketed-based economy sales inside the region?

MR. BALLINGER: They can make opportunity sales within the region. I understand they are capped at a certain cost. So in other words, if their cost -- I guess it's not their cost. If the declining cost -- their incremental production cost was $20 and the buyer's was $30, under the broker network they are

fixed; they can only sell at 25. Under their OS, they might be able to structure a deal to sell at 28. And under the OS they would flow the $8 gain, all of it, back to the ratepayers. Under the broker they would only flow back the $4 of the $5 gain.

COMMISSIONER CLARK: Let me ask another question. Has FPL been predominantly a seller of economy sales or a buyer?

MR. BALLINGER: FPL? They have been predominantly a buyer.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: Florida Power Corporation has been about 50/50, and Tampa Electric Company has been a predominant seller.

Incentives, as we heard earlier, are used to accomplish a goal. I think Mr. Howell was very correct in saying that human nature is to pursue an incentive. And to go out there you do that to get a specific activity out of somebody, be it a child or a utility. I think the incentive has worked. We have gotten a robust wholesale market. We've seen the development of different tariffs and market structures; dedicated personnel that's out there pursuing off-system sales for the benefit of their customers and absent an incentive. To me it's almost

like calling a utility inhuman for pursuing sales without an incentive. I don't see the reason why we need to expand incentive any further. The market is working out there. There's other pressures greater than the 20%.

COMMISSIONER CLARK: What did we do with the broker? We left it at 20%?

MR. BALLINGER: I'm sorry?

COMMISSIONER CLARK: Are we talking about broker sales here, or broker and other economy sales?

MR. BALLINGER: Again, it's how you define economy sales. Tampa Electric Company is taking --

COMMISSIONER CLARK: I want to make a distinction between broker and economy sales.

MR. BALLINGER: That's Issue 12. And if you'd like, I can talk about that. Okay.

The original order that adopted the 20% wasn't precisely clear on that. It was broker only. I think the term used was economy sales split-the-savings. At that time, though, the Florida Broker Network was really the only game in town that was going on.

I would also point out that the Florida Broker system, it is an automated system. It's basically a no-brainer for the utility. They don't

have to have their marketing personnel working that system at all. It's basically the leftover after they have got on the phone, talked with everybody they could. If they have any excess capacity left after all of those deals, they put it on the broker to see if they match up. So it's just kind of -- I call it a wastecan, if you will, that gets thrown over there. I think --

COMMISSIONER DEASON: Let me interrupt for just a second. If I understand what you've just said, you've said that if -- I know you're saying there should be no incentive. But what you just said makes me conclude if there's to be an incentive, that it would be better to apply it to the nonbroker sales as opposed to the broker sales. But the broker sales is a no-brainer. You don't need an incentive. Because after the fact you just post it and if you match, fine, you get a transaction. If you don't, you've already tried to maximize your off-system sales through negotiations and market-based-based rates and things of that nature.

MR. BALLINGER: Well, that's what seems so counterintuitive to me, is you would think that you would need the incentives for these sales that you actually have to work at. But the utilities have

already been pursuing these sales with a vigor. And we've seen increases in those types of sales and a decline in the broker that requires no effort. They are in here now asking that you consider expanding incentives to all those sales. I'd suggest to you there's no need to do it. The market has taken care of that already.

COMMISSIONER CLARK: Well, have we seen an increase in these types of sales for those companies who have been splitting the savings or those companies who have not?

MR. BALLINGER: No. You've seen it primarily in FPL who has been flowing 100% of those gains back.

COMMISSIONER CLARK: But FPL you said is predominantly a buyer.

MR. BALLINGER: But their off-system sales -- off-system sales they made on the broker versus off-system sales they made off the broker through their OS, their OS has been predominant. They are still a net buyer, I believe, of economy energy for their system. When they make a sale, a predominant number of sales is through the OS tariff, not through the broker.

COMMISSIONER CLARK: Could that have been

because they were likely not to be the seller on a broker system?

MR. BALLINGER: No. I think it's they are able to get a better gain through it and have a more flexible deal.

COMMISSIONER DEASON: If you're going to be purchasing, you're more likely to have a more favorable rate if you could get it through the broker. Is that a bad assumption? It's just whether you can -- if enough people are quoting on the broker -- I guess the sellers are getting a better price if they sell at market or some negotiated price as opposed to split A plus B divided by 2. So there's a limited amount of possibilities of getting energy under the broker than compared to previous years. Is that correct?

MR. BALLINGER: I think so. And I think the real key we've seen is flexibility. Everybody likes a product that they can tailor-make to their own specific circumstances. The broker is limited to hour blocks at a time. And it's very fixed on the price. So through OS you can structure it for three hours or an hour and a half if you want. And you may throw a capacity component in it if he needs it for a day. It's much more flexible and allows much smoother

transition and much better for the buyer, quite frankly. They can tailor-make what they really need. A broker is kind of a hit or miss. You're not sure what you're doing to match up and what the actual savings will be. I think with today's communication technology we're able to keep in touch with people much more quickly and arrange those deals.

COMMISSIONER DEASON: Is Staff able to calculate or ascertain the amount of savings derived through nonbroker economy transactions?

MR. BALLINGER: I think in Ms. Harlow's exhibit she had -- I'm looking here at one chart, at least -- and I guess it was just for Gulf, and even that I can't tell over the broker. The only thing I could say is I guess there would be more so just from the fact of the number of sales made. For example, FPL, the predominant number of sales is through OS where a 100% of the gains are going through as opposed to a small number. I believe it was only $17,000 or something this period over the broker.

COMMISSIONER DEASON: No. My question goes to can we, after the fact, look at a transaction and determine the amount of -- I guess the 20% factor that we would allow shareholders to keep is just 20% of what, it would be 20% of the difference between what?

MR. BALLINGER: Well, if you ask me my opinion I'll tell you what I think it should be, but the utilities have interpreted it differently and that's part of the problem. When it's out there they are going to interpret it to best suit their needs. I don't blame them. I would do the same thing if I was in a business.

My perspective is the original broker, when was adopted, was 20% on the gains, and it was that split-the-savings. So if you had a $20 sale and a $30% purchase, the transaction price is at 25, the gain is $5. $1 goes to the stockholders; $4 would come back.

Now, what we've seen is the gain may be -- if it's market-based like Gulf is doing, again you have $20 and $30, but the transaction price might be eight. So Gulf would take 20% of the $8 gain. So since they are doing it differently, I can't tell what it should be applied to.

COMMISSIONER DEASON: That leaves 80% of eight, which is $6.40 as opposed to under the broker it was only four flowing to them. So isn't it better to have the customer get $6.40 as opposed to $4.

MR. BALLINGER: Correct. But I think the way Florida Power & Light is doing it with these

either market-based sales outside of Florida or their opportunity sales inside Florida and flowing 100% of those sales back is even better. And they are making those sales and they are growing. So that's why I don't see where an incentive would increase that activity any more than what it already is.

COMMISSIONER DEASON: But for a utility which engages in market-based transactions, and, say, is it readily ascertainable that the gain is $8, in your example, that their incremental cost is 20 and they actually made the transaction at 28?

MR. BALLINGER: Okay. I didn't follow the question.

COMMISSIONER DEASON: Okay. Under the broker, quotes are given. The selling utility would quote 20 as his incremental cost, and the buying utility would say that 30 is his decremental cost. You'd do the formula and you'd end up at 25. And the selling utility would have a $5 gain; split $4 to ratepayers, $1 to stockholders. We know how that works. And it seems to have worked well. But we're in a different environment now. And what we see is we're seeing a predominance of market-based-based transactions where under our simple hypothetical we're saying that the selling utility perhaps, if he is

capable in the market, probably instead of selling at 25, probably could sell at 28, okay? And in that type transaction, to determine what the 20% should be, which would be 20% times 8, do we have the information, if we ever needed to, to go back and look at that transaction and readily ascertain that the gain was 8. That the incremental cost was 20, and that he sold at 8. And the 20% he keeps of $8, which would be a $1.60, that's really what he should keep. And that his incremental cost really wasn't $22, and that the $28 really was just a $6 gain. Do you see what I'm saying?

MR. BALLINGER: So you're saying do we audit the incremental cost.

COMMISSIONER DEASON: Yeah. Is that something we look at?

MR. BALLINGER: I'm hoping we do. And we should be doing it now under the broker system to make sure the gains are correct. I would say it would be the same thing. And all you're then looking at is what was the transaction price to get your gain.

COMMISSIONER DEASON: But you're not for sure if we do look at that.

MR. BALLINGER: That's not in my area, unfortunately.

COMMISSIONER DEASON: Well, I mean, we talk about incentives, and we have had testimony here that they work. And you incentivize people to do certain things. And that's human nature. And, you know, it's hard to argue against that. It's also going to be human nature if you're going to keep 20% of something, you want 20% of the maximum amount, and, you know, there may be a situation where transactions are interpreted such that you try to maximize the amount of the gains so you get to keep 20% of a larger number. Whereas, maybe the gain is really not that amount. It's something else. That you interpret things differently. I'm not saying anyone would go out and intentionally try to defraud. But we all know that there's certain dynamics involved and maybe interpret things certain ways and at a certain hour you say, well, this is what's happening and this is the way we calculate the gain.

MR. BALLINGER: I agree. And I think anytime you have an incentive out there, I think a rational company decision would be to interpret it to their best interest as much as they could. As much as we've seen already that's happened with the 20%, where some have said 20% applies to market-based-based sales. No, 20% only applies to cost-based sales. No,

20% only applies to broker sales.

COMMISSIONER CLARK: I think the issue is was the 20/80 split limited to economy broker network sales, and did the Order make it clear it was limited to those sales?

MR. BALLINGER: No. That's always been my understanding since I came to the Commission that that's where it applied.

Over the last few years we found out no. And a literal reading of the Order, it's not real clear. All I can point out is that when the Order was passed, the broker system was the predominant marketplace, if you will. There wasn't really such a thing as market-based rates as prolific as they are today. I don't think the Commission really even considered it, to be quite honest with you.

COMMISSIONER CLARK: Tom, let me ask you a question. If we eliminate the incentive, how will we know they have pursued as vigorously as we should economy sales?

MR. BALLINGER: I think you'll notice -- you'll start seeing industrial customers building self-service generators; they haven't pursued them enough. They are not that big of a market, in the first instance, these short-term sales. They are a

small percentage of their overall revenue. I know we have had some figures through the --

COMMISSIONER CLARK: But that seems to argue that it -- that industrial customers building is not really evidence of whether or not they are pursuing it aggressively.

MR. BALLINGER: No. I think the overwhelming thing is there's not a big dollar impact as far as total revenues. I don't know that it will swing anything that they can't -- I think they have every incentive, and they've sat here and told you --

COMMISSIONER CLARK: So how will we know if they aggressively pursue them?

MR. BALLINGER: You can just track the kilowatt-hours of what's going on. I think as Mr. Howell pointed out, it's really difficult because it's really driven by the buyer who's out there. What are they willing to pay it? And it depends on the capacity. Are you short? Are you long? What's going on?

COMMISSIONER CLARK: I think what you're saying is we won't know.

MR. BALLINGER: Right. I think any incentive in the world is not going to change if you don't have a willing buyer.

COMMISSIONER JACOBS: That's what I tried to get out with him. Could you -- is there some benchmark out there so that you would know that if there is this prevailing market price, you'd know there's enough margin -- that buyers will attract sellers.

MR. BALLINGER: I don't think so. And this is exactly the reason why the Commission pulled the projection of economy sales out of base rates to begin with, is it's such a fluid and dynamic market, it's really hard to predict a base level, if you will, a threshold level, because it's really determined by the buyers out there.

COMMISSIONER JACOBS: And given the evolution of how things have occurred, we couldn't tag it on to some index out there, could we? I don't know what it would be --

MR. BALLINGER: I haven't thought of any. I really haven't given that one much thought.

COMMISSIONER JACOBS: The thing that jumps out at me is the price the gas, the price of coal, I mean, one of those factors. And that still wouldn't get you to these situations where you'd have a short-term market -- I'm sorry, short-term demand increases. But it would occur to me that you'd be

able to determine whether or not it's legitimate for them to want to go out in the market and seek out economy sales, and then there will be, of course, a point where they wouldn't necessarily want to, then that's where you want to apply the incentive. Is what you're telling me?

MR. BALLINGER: Yeah. I don't know how you would determine that.

COMMISSIONER DEASON: Sorry. You wouldn't know how to determine what?

MR. BALLINGER: That they should have pursued a sale when they didn't.

COMMISSIONER DEASON: That's the most difficult thing. In that -- we have a difficult enough time, perhaps, in just going in and looking and reviewing the transactions that are made. It would be ten times more difficult to try to go in and say, "You should have engaged in a transaction here that you didn't engage in, and, therefore, we're going to penalize you." That would be an extremely difficult thing to do. But we want companies to maximize those type transactions.

MR. BALLINGER: And I think what Staff is saying is that there's external pressures out there; that they will maximize these short-term sales. Their

basic existence as a company depends on it. Of them marketing not only at the wholesale level, but eventually if we go to retail competition, at that level. They have to develop this market and the skills of working the market and testing the market and being able to respond. They are getting the infrastructure in place. They have had it in place at the wholesale level for several years now. They have staff dedicated doing nothing but combing the market, looking for deals. What does the buyer out there want, is really the first key. Once they identify that, then they structure a deal to try to sell them power.

COMMISSIONER CLARK: Tom, I guess what that says to me is that the competition is getting more and more difficult to make sales, to find buyers to make the sales.

MR. BALLINGER: And I don't think any -- if you gave them 100% incentive, if you told them to divest generation out there where they would keep 100% of any sales, they'd still pursue it vigorously because it's really driven by the buyer. It's driven by what is the demand out there.

COMMISSIONER CLARK: I think if they keep all the profit, I think they'd pursue it even more

vigorously than they are today.

MR. BALLINGER: They might. And that might be the route to go. But what I'm saying is all this talk of incentives is really immaterial because it's really the buyer who is driving it, of these sales. All you do when you add an incentive is you get it perverse, where they will manipulate it to their own best interest.

COMMISSIONER DEASON: But isn't there an incentive to the company to be able to find that elusive buyer out there and to be able to engage in these transactions which maybe -- add to their bottom line. That there's an incentive for them to, first of all, find that buyer, and to make their transaction as attractive as possible. And for it to be attractive and them still make money, that means they have got to operate that much more efficiently. They've got to have the latest technology on line. They've got to have high availability. They've got to have the lowest possible fuel cost. And all of those things work to the advantage of the captive ratepayers as well, if they are doing all of those things to get that little bit of the share when they engage in these transactions.

MR. BALLINGER: I don't disagree with you.

And they are doing that today. And all of the benefits they are getting from those sales are going back to the captive ratepayers who were supporting the plant.

COMMISSIONER DEASON: But what you really can't answer, though, would there be even more sales out there happening -- we know it's growing. And that may be because the market is changing and not because it's the maximum amount already being obtained. It's just because you've seen this growth because the market is just changing, and if there were an incentive we may even see more, which would, by definition -- unless there's out and out fraud, which I'm not certainly not accusing anybody of -- if these transactions take place, it's to the benefit of the captive ratepayer too.

MR. BALLINGER: And, again, I go back to -- this was hammered to me when I was on the witness stand one time -- and we were proposing an emergency broker system at one time. That in order for a transaction to occur, you needed a willing buyer and a willing seller. And it's really the buyer who is driving the market. So all of the incentives in the world is not going to change the amount of sales, in my opinion. It's going to depend on what the buyers

out there are wanting to buy and what they are willing to pay.

COMMISSIONER CLARK: Tom, tell me how this is different from the GPIF.

MR. BALLINGER: It's different in a couple of ways. One, the GPIF has a reward and penalty associated with it. In other words, if a utility misses its targeted mark, they will be penalized actual dollars that get shown as a credit to the fuel clause. The other part is in the GPIF there's kind of a dead band. You set a target and if it falls within a dead band there's no reward or penalty.

COMMISSIONER CLARK: It's a sort of benchmark.

MR. BALLINGER: Yeah. It's not a fixed benchmark. It changes every time you have a fuel hearing.

COMMISSIONER CLARK: But there is an incentive to do well and there's a disincentive?

MR. BALLINGER: I think that's the biggest thing is there's also the flip side of it, the penalty side.

COMMISSIONER DEASON: That just kind of leads into, I guess, some of my concern about what we're doing here today. And I appreciate the analysis

that Staff's done. But it seems to me that when you look at the broader picture what we're really confronting here is what I would consider a major shift in policy. And I'm a little uncomfortable doing that in this proceeding with the short time frames involved and with it being a panel. And while we do have a record here, it seems to me that there's still some unanswered questions out there.

So it seems to me that what my preference would be, would be to keep the status quo until we can have a more thorough review of this entire question. I think this is probably something that the full Commission should address. We know that the marketing which everybody is dealing in has changed tremendously from when this policy was first implemented. I think we need a very thorough review of the question of incentives; if we should have them. And then if we do think they are a good idea, what type of structure that we should have. Obviously, we need to define why transactions should qualify for an incentive. I think we need to address some broad questions, like the marketing costs; whether those should be above or below the line. I think we need to address -- if there is to be an incentive and a shareholder reward, if that should be booked above or below the line.

I know that one of the concerns from Public Counsel is that they are already earning a fair rate of return, and whatever they earn is just going to be in excess of a fair rate of return. And we all know companies have ranges. If they book the shareholder incentive above the line, well, then we know then that they are more likely to earn at the higher end of the range. But if they go over, then we can take some action. Maybe that's the not good idea. But, see, that's the type of thing, ideas, we need to talk about.

I think that there's two sides to something. I think that perhaps what we need is some type of a bar out there to say, well, we know just about anybody probably can achieve "X" amount of these sales, so we're going only to incentivize you if you achieve "X" plus something and then you're going to get your incentive. And I don't know where those levels would be. And maybe that's not a good idea either. But I think that's something we need to talk about.

I think we also need to talk about whether we have the capability to go back after the fact and review these transactions and audit them, if necessary, to determine if we have the capability to verify that this was the company's incremental cost,

this is what they sold at, 20% of it and this is the way it was accounted for and everybody is better off. Obviously, we can't go in and audit all of these things. But perhaps on some type of a routine basis we need to go in and pick out certain transactions and just verify, just as auditors do, you know, take a random sample and satisfy ourselves that everything is happening. Right now I'm not comfortable that we have that capability to do that. I think all these are questions that we need to have answered. I don't think that we are prepared to address all of that here today.

COMMISSIONER CLARK: Tom, haven't we taken this up before? The 20/80 split.

MR. BALLINGER: I tried last time and he threw my testimony out. We talked about the transmission -- it first rose its head when we talked about the transmission treatment, which you addressed last fuel hearing.

COMMISSIONER CLARK: All right. But we have not separated out this issue into a generic proceeding just on incentives.

MR. BALLINGER: No. This proceeding today has been the first time you've actually taken testimony specifically to the 20% incentive.

COMMISSIONER CLARK: Okay. Well, Mr. Chairman, I agree with you, there are lots of things to consider, and I would be uncomfortable changing the policy now. But there seems to be some confusion as to what that policy extends to.

And the question is do we, I guess, allow that confusion to remain, and those they have treated it -- with split-the-savings-the-savings continue, and those who haven't, stay where they are.

COMMISSIONER DEASON: Well, you know, there's a certain, I guess, unfairness in the sense that maybe some utilities have interpreted things a certain way, and maybe that's to their advantage. And others have interpreted it a different way and perhaps that's to their disadvantage. And I hate to perpetuate that, but I'm not prepared at this time, I don't think, to say, "Utility X, you're doing it right and Utility Y, you're going it wrong, and we're going to make you change and you keep doing it the same way."

It seems like -- whatever they are doing right now let them -- for this fuel adjustment period -- just keep the status quo with the ambition of having all of these generic matters addressed before the next fuel adjustment recovery period.

COMMISSIONER CLARK: And I guess we can somewhat rely on the fact that it's for those who haven't pursued it, it's because it hasn't been material to them.

COMMISSIONER DEASON: Perhaps.

COMMISSIONER CLARK: Okay.

COMMISSIONER DEASON: I mean, I don't know -- obviously there are different treatments out there. And we know that when we finally address this from a generic basis there are going to be changes. And some folks or going to change and maybe some folks are going to continue to do it the same. And maybe everybody is going to have to change. I don't know. But I'm not comfortable right now making the decision that one particular utility has interpreted it correctly and another has interpreted it incorrectly and that we need to make changes right here today to effectuate that.

COMMISSIONER CLARK: Then I would move that we deny Staff on Issue 11 with respect to eliminating the 20% shareholder incentive as set forth in that Order.

MR. BALLINGER: Okay.

COMMISSIONER CLARK: I'll get to it at 12.

MR. BALLINGER: Does that preclude us,

though from investigating it further, from what I heard you saying up here?

COMMISSIONER DEASON: I think we definitely need to investigate this further.

COMMISSIONER CLARK: Deny it at this time.

MR. BALLINGER: So I don't think you even vote on Issue 11, then. You tell us to go and either open a separate docket or come back with a recommendation, written recommendation, at a regular agenda, whatever preference is.

COMMISSIONER DEASON: Maybe you want to do that and issue a PAA, or maybe just get with the Chairman's office and go ahead and set this matter for a hearing.

MR. BALLINGER: I'm concerned if we go the hearing route we may not have a decision by the next fuel hearing. It's a very real possibility. But whatever you all want to do is fine with me.

COMMISSIONER DEASON: How long do you think this generic investigation would take?

MR. BALLINGER: In my mind, it would take five minutes, but, you know, I'm trying to approach this with an open mind. (Laughter) I think probably --

COMMISSIONER DEASON: Let me ask -- I know

that this is an extension of the hearing. We're still in the hearing mode. But technically the record is closed at this point. But we've got the parties here. If Staff thinks it's permissible, I'd like to just ask kind of a question to the parties about how they view the likelihood of getting an generic investigation of the magnitude which I've just tried to describe. And usually when you get involved in it, the magnitude expands by two or three times. Whether that's something that can be done in the period of time which would facilitate having all these matters hopefully resolved by the time we get to the next fuel adjustment proceeding. I see Mr. Elias is here and I'll wait for his comment.

MR. KEATING: We think that it's reasonable to ask the question and we would have time before the next fuel adjustment hearing to complete the generic investigation.

COMMISSIONER DEASON: If anybody wants to comment on it, I'll welcome the comments.

MR. STONE: Commissioner, I may be speaking out of turn. However, we initiated a generic investigation as to whether or not to change the fuel cost recovery clause from the six-month to annual calendar year basis. And I believe we initiated that

in December of one year and had it completed in time, so we actually had hearings in November of the following year. So I believe it could be done in that time frame given your schedule, is the issue. And, again, that's just my opinion at this point.

COMMISSIONER DEASON: Mr. McWhirter.

MR. McWHIRTER: Mr. Chairman, I was looking through the exhibits, and Exhibit 37 quotes from a 1992 docket and it's kind of interesting. It said "If the Commission decides to --"

COMMISSIONER DEASON: Exhibit 37 is not in the record.

MR. McWHIRTER: Beg your pardon?

COMMISSIONER DEASON: Exhibit 37?

MR. McWHIRTER: 38.

COMMISSIONER DEASON: Oh, I'm sorry. All right.

MR. McWHIRTER: "If the Commission decides to explore incentives, Staff recommends that this issue be investigated in a generic docket. At that time the Commission can explore the issue of off-system sales, of continued high levels of surplus capacity. This proceeding would allow the Commission the opportunity to adopt a uniform approach." And this was an Order issued in '94, so it's been going on

about five years so far. And you do have testimony in this case. It would be good to bring closure to the subject. Everybody has had an opportunity to deal with it.

Most sales are sales inside of the state of Florida, not outside of the state of Florida. So they are really transfers from one Florida utility to another and in raising the price of some customers over other customers -- well, that's testifying. I'm not going to talk about it any further.

COMMISSIONER DEASON: So you're saying we've already been doing it for four years and there's no need --

MR. McWHIRTER: I just realized that.

MR. WILLIS: I don't think that's true. I think that investigation was -- it was closed for whatever reason. And I think that certainly that this Commission could complete an investigation within a year before the next fuel adjustment proceeding and could look at all of these issues that you've raised, Commissioner Deason.

COMMISSIONER CLARK: I think one of the things that's different is that previously I think the 80/20 split was thought to only have relevance to the broker system. And now it's been demonstrated that it

has further relevance. So even if we had made a decision in the past on the issue of looking at it generically -- I have to confess, it seems like it's lingered on and on. And I thought we had made a determination to continue with it, but apparently we made a determination not to decide it at that point.

Frankly, I'm ready to decide it, but I do think it should be the full Commission that does it.

COMMISSIONER JACOBS: Can we do it this way: Can we modify the recommendation in Issue 11 to say -- and I'm asking for legal advice on this -- to say -- basically to grant it but pending a final decision -- from a generic investigation by the next -- end of the next fuel docket? In other words, can we vote to eliminate it effective the end of the next fuel docket?

COMMISSIONER CLARK: Sunset it.

COMMISSIONER JACOBS: Yeah, sunset it.

COMMISSIONER DEASON: You're saying that we would -- in the absence of an affirmative decision to the contrary, we would be eliminating it.

COMMISSIONER JACOBS: Right.

COMMISSIONER DEASON: I suppose. I don't know if we can do that or not. It's one thing whether we could and another question is whether we should.

MR. ELIAS: I think that's about what I was going to say. I think you can, but that flies in the face of some of the discussion up here with respect to a panel making a broad-based policy decision without the opporutunity for other Commissioners to hear the issue.

COMMISSIONER JACOBS: Sunset is expressly conditioned upon the decision from the full Commission.

COMMISSIONER CLARK: Yeah. But I think what he's saying is that the sunset would be -- it goes away.

COMMISSIONER JACOBS: It's all in how you interpret it. (Laughter)

COMMISSIONER CLARK: Mr. Chairman, I think Mr. Ballinger has suggested that we just not make a decision on 11 and 12. And that's certainly an option. That way it leaves the matter -- I guess we could do it with the understanding that we would take it up in a generic proceeding that would take place before the next fuel adjustment.

MR. BALLINGER: Or your other opportunity would be you have a record in the case. Staff could come back with a written recommendation to the full Commission at a future agenda in a month or two and we

can get closure to this issue much more quickly. If you want to base it on the --

COMMISSIONER CLARK: You mean you could do a PAA.

MR. BALLINGER: It wouldn't be a PAA. It would be a final one because you have a record.

COMMISSIONER CLARK: But then the other Commissioners would have to read it.

MR. BALLINGER: Yes.

COMMISSIONER CLARK: I think you better hold a hearing.

MR. BALLINGER: That's fine with me.

COMMISSIONER DEASON: Now, if we just simply do not address Issues 11 and 12, how does that affect the utilities that have treated certain transactions in one way and others who have treated it a different way?

MR. BALLINGER: I don't think it affects them at all. They keep on doing it, interpreting it the way they have been, is what I understood you to say, is you weren't willing to make a call --

COMMISSIONER DEASON: I just wanted to make sure that we keep the status quo for this recovery period and, hopefully, all of these difficult questions would be answered by sort of the next

recovery period.

MR. BALLINGER: So if I understand, you're asking Staff -- I guess we would open a separate docket first off, have a generic investigation, or whatever we call it, about incentives, 20% incentive. What it applies to. Should it apply to everything? Whatever issues we can come up with. Hearing before the full Commission. And hopefully get this resolved before next November.

COMMISSIONER DEASON: Yeah. But I want to ask Mr. Childs a question. Can we open a generic investigation without it being a rule proceeding, or should it be a rule proceeding? And if we do a generic investigation, what authority do we have to do something? And after the investigation, do we issue it as a PAA? I think you've made certain --

MR. CHILDS: I'm surprised you asked me that question. (Laughter)

I think you can open an investigation. I think you can do that under the statute. My concern is whether you can open what you call 120.57 proceeding under an independent rule and not disclose what action you're proposing to take when you open that docket. But if it's an investigation, we've never objected or said that the Commission couldn't

pursue an investigation.

COMMISSIONER CLARK: We can issue a PAA that says we're going to go away with the 20% incentive and that would be all we have to do.

COMMISSIONER DEASON: Well, I would just encourage Mr. Elias and Mr. Keating to take the legal questions into consideration and hopefully structure this so we're doing it correctly and hopefully can get it done within one year. And I'm sure Mr. Childs can give you his expert advice on how to do that.

(Laughter)

Mr. Childs, I'd assume you'd like to see this done within one year.

MR. CHILDS: I would. But I don't think they need my expert advice to get that done. I think we can do it in a year.

COMMISSIONER CLARK: Mr. Chairman, I would move we take no action on Issue 11 and 12 with the understanding that the way these economy sales are being handled today would remain -- in other words, the status quo would continue, and Staff would institute an appropriate proceeding to reach resolution on whether we should maintain this kind of incentive or have other incentives.

COMMISSIONER JACOBS: The only caveat I'd

have for that is -- and this is kind of a knit, but I think we ought to say that there is credence to the issues raised, and that we expect that they would be resolved in a bench decision. I want this order to have some connotation that we endorse the idea, that the divergent views are acceptable, and that it could be a matter of wordsmithing. But I don't want this order -- because this issue was raised and left not resolved, I don't want there to be some interpretation that we're saying that it's okay to continue ad infinitum with these divergent approaches. I do believe we ought to come up with some consistency.

COMMISSIONER DEASON: Well, I think that the Order probably should say that it's our desire that these are very critical key issues that need to be resolved by the full Commission, needs to be done -- before the next projection period, recovery period. And by the fact that we've not either endorsed Staff's position or rejected it I think speaks for itself that we think that this is a very significant question, and that perhaps there's merit in Staff's argument and there's merit in the parties' arguments and that we'll sort through it all.

COMMISSIONER CLARK: I took his caveat to mean that we don't endorse disparate treatment.

COMMISSIONER DEASON: Oh, oh. Yeah, I agree with that. I think it should be a goal that there should be a consistent treatment. And unless there's some type of showing by a --

COMMISSIONER CLARK: Justification for not --

COMMISSIONER DEASON: -- justification for some unique circumstance to have it treated differently.

COMMISSIONER CLARK: Okay.

MR. BALLINGER: Thank you.

COMMISSIONER DEASON: Issue 13.

MR. BOHRMANN: Issue 13 is when should the utilities file their projection filings and testimonies for 2001 and implied beyond.

In the Prehearing Order, Staff recommended that the projected filings would be due the day after Labor Day, which would be September 5th, 2000. After the prehearing, to be consistent with the environmental cost recovery clause, we -- Staff faxed some proposed stipulation language to the parties which essentially was consistent with what the Commission approved in the ECRC yesterday.

That is, the first business day of April each year the actual true-up from the previous year

would be filed. 90 days prior to the hearing in November the estimated true-up from the current year would be filed, and then 60 days prior to the hearing the projection filings for the following year would be filed. And that's our position -- that's our position today.

COMMISSIONER DEASON: Let me express a concern with the schedule we're operating under for this proceeding. And that is that we're here in the late November making decisions which are going to be implemented in January. And when the issues are more of a routine matter, that's probably not a difficult thing, but I know we have had some nonroutine issues that have come up here. And it places the Commissioners in a difficult situation in that we want to get these matters resolved so the companies can go and implement these factors and get their billing arrangements made and notice can be given to customers. But we're under pressure just like we need to make a bench decision and do it today. And there's not enough time to have a written recommendation.

It seems to me that we may need to view whether we want to have these hearings in late November. It may be that we need to change that to have the hearing so that if the Commission --

whoever -- whichever Commissioners are lucky enough to be on fuel adjustment, that if they wanted the flexibility to have Staff file a written recommendation, that that could be accommodated and still be ample time for utilities to adopt to those factors, implement them and give notice to customers.

MR. BOHRMANN: I agree it would be better if Staff had an opportunity, when conditions warranted, to have a written recommendation. But if the hearing was to be held earlier, that would back things up earlier in the year for the utilities, and there would be a loss of forecasting precision.

COMMISSIONER DEASON: But you're getting a net loss with your recommendation right now.

MR. BOHRMANN: We're conscious of a trade-off that's involved. And I believe under this recommendation there would be about 40 days -- or the estimated actual true-up would be filed 40 days earlier than it was this year, and then the projection filing would be due ten days earlier.

COMMISSIONER CLARK: You know, Mr. Chairman, I don't know what the answer is but this is not satisfactory the way it is. And I think if you look at the last core issue, it seems to me that there ought to be -- you know, when there are routine

issues this works. When they are not routine and when there's a new issue, it doesn't work as well. And that was one reason I asked the question with regard to the last core. Is there a way you can alert us ahead of time with respect to the particular issues, so perhaps we could take up those issues ahead of time and then just have the fuel adjustment.

I don't know what the answer is and I'm not sure I can think of one sitting here, and that's another problem.

COMMISSIONER DEASON: And I can't either. But I guess I can express some dissatisfaction with the way -- and we always have the flexibility, I suppose, to spin things off, which is -- we've just done that, in essence, with the generic investigation. We're not comfortable with the time frames we're having to work under. We're not comfortable making that decision. Of course, we also want the full Commission to handle that because of the policy considerations.

But it is a difficult thing. And I guess what brought it to a head is Staff's wanting to add some more time. And I'm sure that it's necessary to have more analysis time by Staff and the parties but it's not helping us any. Commissioners are sitting up

here having to make the decisions. And it does complicate things. If you add more time, that is, have the hearing set, for example, in early November as opposed to late November, well then you're probably going to ultimately lose another month of actual data and being -- relying even that much more on projections.

MR. BOHRMANN: I would agree.

COMMISSIONER DEASON: Right now we have to address Issue 13 which is fairly specific.

COMMISSIONER CLARK: I take it we have a stipulation in a sense.

MR. BOHRMANN: No, we don't.

COMMISSIONER CLARK: FIPUG does not agree.

MR. BOHRMANN: FIPUG stated that they wanted everything due 90 days prior to the hearing.

MR. McWHIRTER: We'll stipulate 60.

MR. BOHRMANN: Florida Power & Light and Gulf Power indicated they couldn't accept that language.

COMMISSIONER CLARK: They could not.

MR. BOHRMANN: Could not.

MR. KEATING: Florida Power & Light and Gulf both requested that the projected filings and estimated true-up filings be made. I think they would

agree that those could both be made 60 days prior to hearing rather that having estimated 90 days prior to hearing and projected 60 days prior to hearing.

COMMISSIONER CLARK: You know, I'm a little confused. I thought what you had proposed by Staff was consistent with what we did in the energy --

MR. BOHRMANN: ECRC, the environmental.

COMMISSIONER CLARK: Right. Environmental.

MR. BOHRMANN: And it was my understanding that 90 days prior to the hearing they would file their estimated actual true-up for the current year, and then 60 days prior they would file their projection filing.

COMMISSIONER CLARK: Okay.

MR. BOHRMANN: Which is what Staff is proposing -- which is what Staff is recommending for the fuel clause as well.

COMMISSIONER CLARK: Okay. And the difference is that FPL and FPC were not in the --

MR. BOHRMANN: As I understand it, FPL could accept it in the ECRC and so could Gulf. Florida Power is not a party to the 07 docket as of right now.

COMMISSIONER CLARK: Who's objecting to what you're recommending here?

MR. BOHRMANN: As far as I know FPL and Gulf

is. The other parties have indicated that they can accept that language.

COMMISSIONER DEASON: And exactly what is it that FPL and Gulf find objectionable?

MR. BOHRMANN: They've talked to me -- that information is not on the record. I'm not aware if I can --

COMMISSIONER DEASON: If it's not on the record, I don't need to know it then.

MR. BOHRMANN: I have had some phone conversations with representatives from --

COMMISSIONER DEASON: I don't need to know if it's not in the record. If they have an objection stated in the record I want you to refresh my memory as to what that is, if there's anything in the record.

MR. BOHRMANN: I don't believe there's anything in the record that would indicate the source of their objection.

COMMISSIONER DEASON: Why is it Staff feels this change is necessary?

MR. BOHRMANN: Right now we're basically operating almost with zero room for error. This year Florida Power & Light was affected by a hurricane in late September which pushed their filing back a week. The same thing happened with Gulf Power last year, and

that created a cascading effect of parties asking for additional time to file this pleading or that pleading. And as it stands right now, this year we received the filings on October 1st, and the prehearing was November 4th, which is a total of 34 days. And typically the Commission allows parties to respond to interrogatories and PODs in 35 days. So essentially, you know, there was not even time to do one round of discovery, even if we were to send out discovery the same day we received the filings and have a position available at the prehearing.

The parties, I might add, have made a good-faith effort to cooperate as much as possible in answering our discovery responses. So it's not that that Staff has a concern with, it's just there's not enough time built into the process as it is. And we're asked for an additional ten days for the projection filings and an additional 40 days for the estimated actual true-up.

COMMISSIONER DEASON: It seems to me then, Commissioners, the balance we're trying to reach here is -- we're going to be losing some precision in the projections the earlier that you have them made, but then at the same time the longer our Staff has to review those, perhaps the more -- the better the

analyses and recommendations we're going to be getting from our Staff. Somewhere there's a balance in there. Right now Staff is indicating that right now it's a little tilted against their having adequate time to review that information and engage in meaningful discovery even though the parties have been very cooperative in trying to provide discovery responses.

Whatever your pleasure.

COMMISSIONER CLARK: I move Staff.

COMMISSIONER JACOBS: Well, I was just thinking about -- okay. Staff is going for the 90 days?

COMMISSIONER CLARK: Staff, would you repeat your recommendation?

MR. BOHRMANN: Oh, I'm sorry.

First business day of April the utilities would file their actual true-up from the previous year. 90 days prior to hearing the utilities would file their estimated true-up from the current year. And 60 days prior to hearing the utilities would file their projection testimony and filings for the following year.

COMMISSIONER JACOBS: Okay. Second.

COMMISSIONER DEASON: Moved and seconded. Show then that recommendation is approved unanimously.

Issue 14 has been eliminated. Issue 15, eliminated. Issue 16A.

MS. LEE: Commissioners, Issue 16A is FPL's request for recovery of the last core of nuclear fuel through the fuel clause.

We heard testimony today -- well, yesterday, as a matter of fact, from Witness Wade and also FPL Witness Dubin. That's an issue that also concerns Florida Power Corp since they also have a nuclear facility. Florida Power Corp did not address this issue, as you heard today.

I would like to suggest that we take this issue and spin it out and address it on an generic basis for both Florida Power & Light and Florida Power Corp.

It concerns me that the Orders that were referred to by Mr. Wade are Orders in which the last Courts considered a rate base item. Is that appropriate? I'm not sure. But yet that is the only information we have at this time.

I would like to hear what Florida Power Corp has and see whether we can get some more information on it before we go forward and make a decision.

COMMISSIONER DEASON: I have no objection to spinning it out. If we do take that, I would like to

take advantage of that opportunity and look at the possibility of allowing recovery and having the amounts put into a funded reserve similar to what we do for nuclear decommissioning.

MS. LEE: Absolutely. Absolutely. I don't know what -- I mean, it's a funded reserve. I don't know what IRS implications there are. There are a lot of things that, yes, we would have to look into. Yes. Definitely.

COMMISSIONER CLARK: I move Staff with that caveat.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Moved and seconded. Show then Staff's recommendation with that clarification on 16A is a approved.

16B is withdrawn. 16C, I think, is being referred to the full Commission. 17D withdrawn. 17E, full Commission. 19B eliminated. 19D eliminated. 19E.

MR. BOHRMANN: 19E asks should the Commission --

COMMISSIONER DEASON: Is your microphone on?

MR. BOHRMANN: Sorry. 19E asks "Should the Commission allow the incremental cost replacement fuel and purchased power cost associated with the explosion

that occurred at Gannon Unit 6 on April 9, 1999?"

Staff recommends that -- Staff recommends that the Commission allow these incremental replacement fuel costs.

Staff conducted discovery on this issue almost from the time that Gannon Unit 6 was back up and running. We had a deposition of Witness Black last month. We toured the Gannon plant. We have an understanding of the facts which led up to the explosion. But in the past, Commission policy has set a rather high standard for disallowing replacement fuel cost.

COMMISSIONER CLARK: You mean the Florida Supreme Court has set a high standard.

MR. BOHRMANN: I stand corrected.

COMMISSIONER CLARK: I mean, they have set the standard for these types of things. Would that be correct, Mr. Keating?

MR. KEATING: Yes.

COMMISSIONER CLARK: Okay.

MR. BOHRMANN: And Staff feels that in this instance, it does not rise to the level that would cause a disallowance of fuel cost to occur.

COMMISSIONER CLARK: What is the standard that has been set for this type of issue?

MR. BOHRMANN: A systemic management imprudence --

COMMISSIONER CLARK: Imprudence.

MR. BOHRMANN: Imprudence that can be proved based upon information that was know or should have been known before the accident took place.

COMMISSIONER CLARK: Okay.

COMMISSIONER DEASON: Is there a recommendation?

COMMISSIONER JACOBS: What are the numbers? Do you agree with the numbers, with the 1 million -- 1.7?

MR. KEATING: I'm sorry. I didn't hear you.

COMMISSIONER JACOBS: Are you in agreement with the 1.7 figure?

MR. BOHRMANN: Yes.

COMMISSIONER CLARK: I move Staff.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Moved and second. Show then approves Staff recommendation on 19E unanimously. 19H.

MS. LEE: Commissioners, can we go back to Issue 16A for just one minute?

Let me clarify that -- and you didn't address this in your motion or in your vote. But the

recovery that FPL is seeking in this proceeding we would not address until we did the generic proceeding. Is that correct?

COMMISSIONER CLARK: We would not allow recovery.

COMMISSIONER DEASON: We would not allow recovery --

MS. LEE: Would not allow recovery at this time.

COMMISSIONER DEASON: That's correct.

MS. LEE: Thank you.

COMMISSIONER CLARK: If we've done it wrong, we can keep it -- doing it wrong for a little bit longer.

MS. LEE: Thank you.

COMMISSIONER DEASON: 19H.

MR. BOHRMANN: 19H asks whether the energy costs associated with five purchased power agreements between Tampa Electric Company and Okeelanta Corporation, Farmland Hydro, Auburndale Power Partners and Hardee Power Partners prudent and appropriate for recovery through the fuel and purchased power cost recovery clause.

And our position is that we don't oppose Tampa Electric from recovering these costs. We feel

as if additional discovery should be done before the next fuel hearing. And if we find any reason to bring these back to the attention of -- back to the attention the Commission, we will raise the issue. But for the time being, we believe these costs should be recovered through the fuel clause.

COMMISSIONER DEASON: Questions or a motion?

COMMISSIONER CLARK: I move Staff.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Moved and seconded. Show then Staff's recommendation on 19H is approved unanimously. 19I.

MR. BOHRMANN: 19I asks "What are the costs associated with accelerating the commercial in-service date of Polk Unit 2, Tampa Electric Company's next generation unit, from January 2001 to October 2000?" Referring to only costs that flow through the fuel clause in this issue. Our recommendation on Issue 19I mirrors that of 19H.

COMMISSIONER CLARK: I move Staff.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: It's been moved and seconded. Show then that Staff's recommendation on 19I is approved unanimously. 19J.

MR. BOHRMANN: 19J asks "Should the

Commission approve Tampa Electric's proposed regulatory treatment for its wholesale power supply agreement with Florida Municipal Power Agency for January 1, 2000 through March 15, 2001?"

Staff essentially agrees with the Tampa Electric's position with the following two modifications: The Commission established in 1997 a generic policy on dealing with wholesale sales and whether or not to separate. And essentially what that Order states is that if a wholesale sale is long term and firm, then it should be separated from the retail jurisdiction at system average cost.

The Order also stated that on a case-by-case basis the Commission could approve a different recovery if ratepayer benefits were shown.

Witness Hernandez had an exhibit which showed that the ratepayers will benefit from this wholesale sale taking place under their treatment, and in order to ensure that the ratepayers will be better off, at the end of the wholesale contract we will want Tampa to examine and compare the total revenues generated from the FMPA sale and determine whether or not those revenues are greater that the sum of the following: The unit incremental fuel cost for Big Bend 2 and 3 and Gannon 5 and 6 as -- in whatever

weights they were used to serve the sale. The system average SO2 emission allowance cost, and the system average variable O&M cost.

If the revenues generated are greater than the sum of these three figures, then the ratepayers will be better off. If the revenue is less than the sum of these three figures, then Tampa Electric should make up the shortfall from operating revenues. That would be the Staff's first modification.

The second modification would be a change in how the cost -- how the revenues, excuse me, are allocated to different fuel clauses.

Tampa Electric proposed that an amount equal to the system average SO2 emission allowance be credited to the ECRC to compensate the ratepayers for the additional emission allowances that that sale would create, and then everything else would flow through the fuel clause.

Staff proposes a slight modification in that. Staff would have Tampa Electric crediting the capacity and transmission revenues generated from the sale, and credit those revenues to the capacity clause, keep the same treatment for the ECRC and have all remaining revenues flow to the fuel clause.

With these modifications, Staff can get with

Tampa Electric's treatment of the FMPA wholesale sale.

COMMISSIONER DEASON: I have a question on your first modification. You wanted to compare total revenues from the contract to the total of three separate items. The first being incremental fuel cost from the units, which are utilized to serve the contract.

MR. BOHRMANN: Yes.

COMMISSIONER DEASON: And the second was system average SO2 allowance cost.

MR. BOHRMANN: Yes.

COMMISSIONER DEASON: What do you mean by "system average."

MR. BOHRMANN: Instead of looking at the total -- TECO's total system, what the average was, the average cost of their emission allowances.

COMMISSIONER DEASON: Is there any way to identify that on an incremental basis for this particular -- to serve this particular contract? Is it that the information is not available or is it because Staff believes system average is superior to incremental?

MR. BOHRMANN: It's been my experience that it's easier to track system average than it is to track incremental.

COMMISSIONER DEASON: Do you agree -- but theoretically it would be better to do it on an incremental basis. Is that what the whole analysis is about is incremental revenue versus incremental cost?

MR. BOHRMANN: Yes. If we were able to track that data more easily, that would be better, but --

COMMISSIONER DEASON: What is TECO's position? Do they acquiesce to system average or do you know?

MR. BOHRMANN: I believe Tampa Electric has said that they can accept that position.

COMMISSIONER DEASON: System average. Now, what was the third component?

MR. BOHRMANN: System average variable O&M.

COMMISSIONER DEASON: System average variable O&M. The same question applies to this system average portion of the variable O&M. Is it that that's just information that's readily available and Staff believes that it would suffice to use it as opposed to some type of incremental?

MR. BOHRMANN: Yes.

COMMISSIONER DEASON: What's TECO's position on that?

MR. BOHRMANN: The same as with the emission

allowance.

COMMISSIONER DEASON: They agree that it could be done on a system average basis.

MR. BOHRMANN: Yes.

COMMISSIONER DEASON: Now, it's your recommendation that it be modified such that if that comparison is made and total revenues are less than the sum of the three components, which you just identified, that TECO would have to make ratepayers whole for that difference.

MR. BOHRMANN: Yes.

MR. HERNANDEZ: May I ask a clarifying question? Is that appropriate?

COMMISSIONER DEASON: Let me finish up with Staff, and then we'll -- .

I guess my concern is, is that Monday morning quarterbacking? I mean, shouldn't the standard be based upon what TECO knew at the time they entered into the contracts, was it reasonable for them to conclude that this was a benefit to customers? Or do we hold them to a standard that, well, we don't care what happens in the mean time, we're going to do, after a fact, an analysis. And if our numbers don't total the way we want them to total, well, then we're going to hold you responsible.

MR. BOHRMANN: In the generic policy which set up how to separate wholesale sales, it states that the Commission can approve an alternate treatment if ratepayer benefits would occur. And this comparison will ascertain whether or not the ratepayers were better off with Tampa Electric serving FMPA.

COMMISSIONER DEASON: Well, my concern is if that is the standard we're going to employ, are we sending a signal to utilities don't engage in any of these off-system sales unless you're so certain that after the fact there's going to be a net positive. Are we saying to them even though you may be slightly sure, just forget it, because if you can't prove it with 100% accuracy and certainty after the fact, well, then we're going to penalize you. And is that what we want our utilities to do? Or do we want them to pursue -- if they can demonstrate on the front end that we think, based upon what everybody knows at the time, that it's reasonable to assume that this is a prudent and cost-effective transaction for ratepayers and have them pursue that. I mean, there's a difference in the standard. And is that the standard you all want to employ? Do you understand the distinction I'm making?

MR. BOHRMANN: Yes. I understand your

distinction. My reading of the Order which set up for generic policy I do not interpret -- I did not interpret the sentence which stated that net ratepayer benefits will need to occur, I did not interpret that as being just a before-the-fact --

COMMISSIONER DEASON: I may interpret that differently. Okay. But -- and I guess that would be for the Commission to decide. But I'll be glad to share with you that when -- I would probably interpret that when it talks about demonstrating net ratepayer benefits, that it's based upon what was known at the time that the contract was entered into. Was it reasonable to assume that this was a cost beneficial transaction for captive retail customers and that that should be the standard?

But it seems to me -- I'm not opposed to having this information provided as part of your modification, your first modification. I guess I would not be willing at this point to say if the numbers show X, then we're going to do Y; if they show A, we're going to do B. Just get the information and then we'll make a determination at that time. And maybe when the numbers come in, it's a nonissue.

MR. BOHRMANN: I would hope that to be the case, but we will do that.

COMMISSIONER CLARK: What is the second modification again?

MR. BOHRMANN: Second modification is to allocate the capacity and transmission revenue from the sale to the capacity cost recovery clause instead of the fuel clause as Tampa Electric proposed originally.

COMMISSIONER CLARK: I would move Staff with the exception that we just have the information provided, but we take -- make no decision with respect to any action that we would take.

Mr. Chairman, I agree with you, that I think it was a showing to be made on the front end. If it appears that the benefits are there, then it can be included and not separated out.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Okay. It's been moved and second. Show then --

COMMISSIONER CLARK: I would note to that FIPUG, as I understood it, at the hearing said -- at least for this transaction they had concluded that there were benefits to customers, and that they had changed their position on it.

MR. BOHRMANN: Yes. I agree that based upon the information it shows that there are net ratepayer

benefits.

COMMISSIONER DEASON: Okay. Show then that Staff's recommendation on 19J as clarified by the Commissioners' discussion is approved unanimously.

We have a -- 19K through O have been eliminated. Issue 17 and 28, are those fallout numbers?

MR. KEATING: Yes, those are fallouts. I believe all we have left is Issue 31.

COMMISSIONER DEASON: Let's go to Issue 31.

MR. BOHRMANN: Issue 31 asks "Are capacity costs associated with five purchased power agreements between Tampa Electric Company and Okeelanta Corporation, Farmland Hydro, Auburndale Power Partners and Hardee Power Partners prudent and appropriate for recovery through the capacity cost recovery clause?" And our position for this issue mirrors our position for Issues 19H and 19I.

COMMISSIONER CLARK: Move Staff. We have to move Staff to be consistent, right?

MR. BOHRMANN: Yes.

COMMISSIONER JACOBS: Second.

COMMISSIONER DEASON: Moved and seconded. Show then Staff's recommendation on Issue 31 is approved. And the remaining issues are fallout

issues; is that correct?

MR. KEATING: Correct. We have Issue 2.

COMMISSIONER DEASON: 2, 3, 4 and 7 or --

MR. KEATING: The issues that have not yet been voted are 2, 3, 4, 7, 27 and 28.

COMMISSIONER DEASON: Okay. Staff, what order should we take those? Can we just -- Staff is going to have to do some recalculations on some of these matters; is that correct?

MR. KEATING: Yes. That's correct.

COMMISSIONER CLARK: I thought what we indicated is that they would resubmit their numbers. If there's agreement, Staff would approve them administratively.

MR. KEATING: Is that what was done in the environmental docket?

COMMISSIONER CLARK: Yes.

MR. STONE: Commissioners, if I may, Gulf has handed out its revised schedules and I have copies for the Commissioners if you'd like them.

COMMISSIONER DEASON: Would it be -- should we take a short recess at this time or --

COMMISSIONER CLARK: I don't think a short recess is going to cure it.

COMMISSIONER DEASON: Staff, how do you want

to proceed at this point? Do you want just authority from the Commission to approve the final numbers administratively? Is that sufficient?

MR. KEATING: Yes.

COMMISSIONER DEASON: Mr. Keating, is that sufficient?

MR. KEATING: Yes, that would be sufficient.

COMMISSIONER DEASON: And that would be for Issues 2, 3, 4, 7, 27 and 28?

MR. KEATING: Yes.

COMMISSIONER DEASON: Is there anything else to come before the Commission at this time?

MR. KEATING: I believe Mr. Childs has something to add.

COMMISSIONER DEASON: Mr. Childs.

MR. CHILDS: I didn't think -- I think it's implicit in what was moved before by Commissioner Clark on Issues 25 and 26, but 30 was the issue on AES and I just didn't want to leave it there as an issue that wasn't addressed. That's the main issue on AES Cedar Bay and I think that it's implicit with what you already voted or moved on 25 and 26.

COMMISSIONER CLARK: Right. It would be moved to a separate proceeding.

COMMISSIONER DEASON: But we were going to

allow recovery during this recovery period.

MR. CHILDS: I just didn't want the issue to be left unaddressed.

MR. KEATING: It was my understanding that that was one that yesterday, prior to hearing, we took up as a preliminary matter along with the energy payment on that contract, and along with the Power Corp and Lake Cogen issue, 17E.

COMMISSIONER DEASON: Okay. Anything else to come before the Commission at this time?

(No response.)

I guess not. I would just thank the parties for all of your hard work and efforts. And we're going apparently to have some generic investigations of some sort. And I just ask for your future cooperation in those endeavors as well.

And with nothing else before the Commission at this time, the hearing is adjourned.

(Thereupon, the hearing concluded at 4:48 p.m.)

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

We, JOY KELLY, CSR, RPR, Chief, Bureau of Reporting, KIMBERLY K. BERENS, CSR, RPR, Commissioner Reporters, and NANCY METZKE, RPR

DO HEREBY CERTIFY that the Hearing in Docket No. 990001-EU 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 784 pages, Volumes 1 through 5, constitutes a true transcription of our notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

DATED this 7th day of December, 1999.

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

KIMBERLY K. BERENS, CSR, RPR
FPSC Commission Reporter

NANCY METZKE, RPR

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1.7 769/12, 769/15
10 703/3, 706/15, 712/19, 717/9, 722/25
100% 727/13, 729/18, 731/2, 738/19, 738/20, 777/14
11 696/7, 704/16, 713/1, 717/4, 717/9, 717/10, 746/20, 747/7, 751/10, 752/17, 753/14, 755/18
12 696/7, 696/8, 704/16, 715/1, 722/25, 725/15, 746/24, 752/17, 753/14, 755/18
120.57 754/21
13 696/6, 696/8, 702/23, 715/1, 757/12, 757/13, 761/10
14 699/25, 766/1
15 772/4
16A 696/9, 766/2, 766/3, 767/15, 769/23
16B 696/9, 767/16
16C 696/9, 767/16
17 700/2, 780/6
17A 697/9
17B
17C
17D 696/9, 767/17
17E 696/9, 767/17, 783/8
18A 697/9, 700/3
18B 697/9
1984 718/8, 722/10, 722/11, 722/20
1992 749/9
1997 772/7
1999 768/1, 784/11
19A 697/9, 700/3
19B 696/10, 767/18
19C 697/9, 700/3
19D 696/10, 767/18
19E 696/10, 767/19, 767/20, 767/23, 769/20
19F 697/9, 700/3
19G 697/9, 700/3
19H 696/10, 769/21, 770/16, 770/17, 771/11, 771/19, 780/18
19I 696/10, 771/12, 771/13, 771/18, 771/24, 780/18
19J 696/10, 771/24, 771/25, 780/3
19K 780/5
19K-O 696/11
1st 701/2, 764/4

2

2 697/16, 698/3, 698/5, 698/6, 702/1, 702/12, 723/13, 728/13, 771/15, 772/25, 781/2, 781/3, 781/5, 782/9
20 731/10, 731/16, 732/7
20% 704/11, 704/14, 717/12, 717/25, 718/20, 718/25, 719/6, 719/11, 719/15, 719/24, 722/9, 722/12, 725/5, 725/7, 725/17, 729/23, 729/24, 729/25, 730/9, 730/17, 732/3, 732/4, 732/8, 733/6, 733/7, 733/10, 733/23, 733/24, 733/25, 734/1, 744/1, 744/25, 746/21, 754/5, 755/3
20/80 734/3, 744/14
2000 757/18, 771/16, 772/4
2001 757/15, 771/16, 772/4
20A 697/10, 700/3
20B 697/10
20C
21 700/4
22 697/10, 700/4
23 697/10, 700/4
24 697/10, 700/4
25 697/10, 698/11, 699/10, 699/14, 699/21, 700/10, 700/15, 701/17, 724/1, 730/11, 731/18, 732/2, 782/18, 782/22
26 697/10, 698/11, 699/10, 699/14, 699/21, 700/10, 700/15, 701/17, 782/18, 782/22
27 781/5, 782/9
28 724/2, 731/11, 732/2, 780/6, 781/5, 782/9

3

3 697/17, 698/3, 698/5, 698/6, 702/1, 702/12, 772/25, 781/3, 781/5, 782/9
3% 705/14
30 731/17, 782/18
30% 705/11
31 696/12, 780/9, 780/10, 780/11, 780/24
34 764/5
35 764/7
37 749/8, 749/11, 749/14
38 749/15

4

4 697/3, 702/1, 702/12, 781/3, 781/5, 782/9
40 759/17, 759/18, 764/18
4:48 783/20
4th 764/5

5

5 697/8, 700/2, 772/25, 784/9
50/50 724/13
5th 757/18

6

6 697/9, 700/2, 768/1, 768/6, 772/25
60 758/3, 761/17, 762/1, 762/3, 762/12, 765/20
697 696/5

7

7 702/1, 781/3, 781/5, 782/9
702 696/6
704 696/7
715 696/8
767 696/9
771 696/10
780 696/11, 696/12
784 784/9
7th 784/11

8

8 697/9, 700/2, 732/4, 732/7, 732/8
80% 730/20
80/20 750/24
888 703/11, 703/14, 717/17, 719/20, 721/4, 721/7

9

9 696/6, 702/23, 703/1, 703/3, 703/10, 705/20, 706/14, 722/2, 768/1
90 758/1, 761/16, 762/2, 762/10, 765/11, 765/18
990001-EU 784/5

A

absence 704/5, 751/20
absent 724/25
accelerating 771/14
accept 761/19, 762/21, 763/2, 775/12
acceptable 756/6
access 710/21
accident 769/6
accommodated 759/4
accomplish 724/16
accounted 744/2
accuracy 777/14
accusing 740/14
achieve 743/15, 743/16
acquiesce 775/9
action 743/9, 754/23, 755/18, 779/11
actions 708/12
activity 723/9, 723/10, 724/19, 731/6
add 739/6, 739/12, 760/22, 761/2, 764/12, 782/14
added 711/16, 719/22, 721/12
address 698/9, 699/13, 701/21, 702/20, 704/16, 715/3, 742/13, 742/21, 742/23, 744/11, 746/9, 753/14, 761/10, 766/10, 766/13, 769/25, 770/2
addressed 701/24, 744/18, 745/24, 782/20
addresses 717/9
adds 723/15
adequate 714/18, 765/4
adjourned 783/18
adjustment 745/22, 745/25, 748/13, 748/17, 750/19, 752/21, 759/2, 760/7
adjustments 700/18
administratively 781/14, 782/3
adopt 749/24, 759/5
adopted 722/12, 725/17, 730/9
advantage 739/21, 745/13, 767/1
advice 751/11, 755/10, 755/15
AES 782/18, 782/20
affect 753/14
affected 700/25, 717/24, 717/25, 763/23
affecting 723/5
affects 698/22, 753/18
affirmative 751/20
Agency 772/3
agenda 747/10, 752/25
aggressively 735/6, 735/13
agree 704/13, 710/25, 716/13, 733/19, 745/2, 757/1, 759/7, 761/8, 761/14, 762/1, 769/11, 775/1, 776/2, 779/12, 779/24
agreed 701/7, 720/10
agreement 697/20, 697/23, 700/11, 769/14, 772/3, 781/13
agreements 770/18, 780/12
agrees 704/10, 772/5
alert 760/4
allocate 704/2, 711/8, 779/4
allocated 773/12
allocates 703/24
allocation 704/1, 705/11, 705/14, 705/15, 706/23, 709/6, 709/7
allocator 705/18, 711/6
allow 711/14, 729/24, 745/6, 749/23, 767/24, 768/3, 770/4, 770/6, 770/8, 783/1
allowance 773/2, 773/14, 774/10, 776/1
allowances 773/16, 774/16
allowed 706/2
allowing 767/2
allows 728/25, 764/6
alternate 777/3
ambition 745/23
amount 728/14, 729/9, 729/23, 733/7, 733/9, 733/12, 740/9, 740/24, 743/15, 773/13
amounts 700/11, 700/15, 708/5, 767/3
ample 759/5
analyses 765/1
analysis 711/11, 741/25, 760/24, 775/3, 776/23
annual 748/24
answer 740/6, 759/22, 760/8
answered 744/10, 753/25
answering 764/14
applicable 707/12
applied 699/1, 704/14, 730/19, 734/8
applies 713/8, 733/24, 733/25, 734/1, 754/6, 775/17
apply 704/25, 713/4, 726/14, 737/5, 754/6
appreciate 741/25
approach 747/22, 749/24
approaches 756/11
appropriate 697/7, 700/18, 705/7, 755/22, 766/19, 770/21, 776/13, 780/15
approval 697/7
approve 699/19, 701/18, 702/4, 712/19, 772/1, 772/14, 777/3, 781/13, 782/2
approved 702/12, 717/8, 757/23, 765/25, 767/15, 771/11, 771/24, 780/4, 780/25
approves 700/7, 769/20
April 757/24, 765/16, 768/1
area 732/24
argue 709/19, 733/5, 735/3
argument 720/7, 756/21
arguments 719/21, 756/22
arose 717/16
arrange 729/7
arrangements 758/18
ascertain 729/9, 732/6, 777/5
ascertainable 731/9
associated 703/8, 707/18, 741/7, 767/25, 770/18, 771/14, 780/12
assumption 728/9
attention 771/3, 771/4
attract 736/5
attractive 739/15
Auburndale 770/20, 780/14
audit 732/13, 743/23, 744/3

auditors 744/6
authority 754/14, 782/1
automated 725/24
availability 739/19
available 709/1, 764/11, 774/20, 775/19
average 772/12, 773/2, 773/3, 773/14, 774/10, 774/13, 774/15, 774/16, 774/21, 774/24, 775/9, 775/13, 775/15, 775/16, 775/18, 776/3

B

backup 718/18
bad 728/9
balance 764/21, 765/2
band 741/11, 741/12
bar 743/14
base 701/8, 704/2, 723/7, 736/9, 736/11, 753/2, 766/18
based 703/24, 705/4, 705/8, 706/3, 706/4, 708/6, 712/13, 769/5, 776/18, 777/18, 778/11, 779/24
basis 706/24, 708/6, 708/7, 709/19, 710/22, 711/9, 711/18, 719/4, 744/4, 746/10, 748/25, 766/14, 772/14, 774/18, 775/3, 776/3
Bay 698/21, 700/11, 700/25, 782/21
beating 723/1
before-the-fact 778/5
Beg 749/13
bench 756/4, 758/20
benchmark 736/3, 741/14, 741/16
Bend 772/25
beneficial 778/13
benefit 711/7, 711/10, 724/24, 740/15, 772/17, 776/20
benefits 704/5, 706/23, 740/2, 772/15, 777/4, 778/4, 778/11, 779/14, 779/22, 780/1
BERENS 784/3
big 734/24, 735/8, 772/24
biggest 741/20
billing 758/17
bit 718/3, 721/11, 739/23, 770/13
Black 768/7
blame 730/6
blocks 728/21
book 743/5
booked 742/25
bookkeeping 702/17
bottom 739/12
bridge 721/13
bring 750/2, 771/2
broad 742/21
broad-based 752/4
broader 742/2
broken 721/8
broker 712/23, 716/9, 717/12, 718/10, 718/13, 719/19, 720/10, 720/15, 720/20, 720/23, 721/20, 722/4, 723/8, 723/9, 723/25, 724/4, 725/7, 725/10, 725/14, 725/18, 725/21, 725/24, 726/5, 726/15, 727/3, 727/18, 727/19, 727/24, 728/2, 728/8, 728/10, 728/15, 728/20, 729/3, 729/14, 729/20, 730/8, 730/21, 731/15, 732/18, 734/1, 734/3, 734/12, 740/20, 750/25
brought 760/22
build 707/1, 708/8, 710/25
Building 714/6, 714/15, 734/22, 735/4
built 708/10, 708/23, 715/25, 764/16
bundled 719/17, 720/6, 720/14, 720/16, 720/25
Bureau 784/3
bushes 723/1
business 723/3, 730/7, 757/24, 765/16
buy 741/1
buyer 718/17, 724/8, 724/10, 727/16, 727/21, 729/1, 735/17, 735/25, 738/10, 738/22, 739/5, 739/11, 739/14, 740/21, 740/22
buyer's 723/25
buyers 736/5, 736/13, 738/16, 740/25
buying 709/2, 712/14, 731/16

C

calculate 729/9, 733/18
calculated 701/8
calendar 748/25
Call 697/4, 716/3, 717/13, 719/2, 722/23, 726/6, 753/21, 754/5, 754/21
came 718/8, 719/20, 721/8, 723/6, 734/7
cancel 713/19
capability 743/22, 743/24, 744/9
capacity 698/17, 698/21, 699/10, 703/19, 703/23, 704/7, 704/22, 705/23, 706/18, 707/1, 707/4, 707/6, 707/8, 707/10, 707/12, 707/17, 707/21, 707/24, 707/25, 708/6, 708/8, 708/10, 708/16, 708/18, 708/25, 709/5, 709/25, 710/4, 710/8, 710/10, 710/14, 710/25, 711/9, 711/13, 711/22, 712/5, 712/7, 712/15, 713/9, 713/25, 714/6, 715/5, 715/6, 715/8, 715/12, 715/13, 715/18, 715/19, 715/23, 715/25, 716/2, 716/11, 716/22, 716/23, 716/24, 718/18, 722/2, 722/23, 726/4, 728/24, 735/19, 749/23, 773/21, 773/22, 779/4, 779/5, 780/11, 780/16
capacity-related 707/2, 711/15, 711/20
capacity-type 716/17
capped 723/21
captive 739/21, 740/3, 740/16, 778/14
care 727/6, 776/22
carries 701/16, 706/13
cascading 764/1
case 704/6, 704/21, 711/16, 723/6, 750/2, 752/23, 778/25
case-by-case 772/13
caveat 716/14, 755/25, 756/24, 767/11
Cedar 698/21, 700/11, 700/25, 782/21
certainty 777/14
CERTIFICATE 784/1
CERTIFIED 784/7
CERTIFY 784/5
Chairman's 747/13
change 715/24, 735/24, 740/24, 745/19, 746/11, 746/13, 748/23, 758/24, 763/20, 773/10
changed 722/11, 723/3, 742/14, 779/23
changes 722/14, 741/16, 746/10, 746/17
changing 740/8, 740/11, 745/4
charge 703/12, 703/15, 707/18, 707/20, 707/24, 707/25, 716/2, 716/17, 720/12, 720/19
charged 703/15, 720/13
charges 714/4, 720/19
chart 729/12
cheaper 712/15
Chief 784/3
child 724/19
circumstance 757/8
circumstances 728/20
claim 719/15, 719/24
clarification 697/15, 767/15
clarified 780/3
clarify 769/24
clarifying 776/12
CLARK 697/18, 699/18, 700/2, 700/9, 700/14, 701/18, 702/11, 704/17, 705/21, 706/1, 706/7, 712/11, 712/18, 714/6, 715/2, 716/7, 716/19, 717/3, 717/20, 719/16, 720/2, 720/14, 721/7, 721/16, 721/24, 723/17, 724/6, 724/11, 725/6, 725/9, 725/13, 727/8, 727/15, 727/25, 734/2, 734/17, 735/3, 735/12, 735/21, 738/14, 738/24, 741/3, 741/13, 741/18, 744/13, 744/20, 745/1, 746/1, 746/6, 746/19, 746/24, 747/5, 750/22, 751/17, 752/10, 752/15, 753/3, 753/7, 753/10, 755/2, 755/17, 756/24, 757/5, 757/10, 759/21, 761/11, 761/14, 761/21, 762/4, 762/8, 762/14, 762/18, 762/23, 765/9, 765/13, 767/10, 768/13, 768/16, 768/20, 768/24, 769/3, 769/7, 769/17, 770/4, 770/12, 771/8, 771/20, 779/1, 779/8, 779/19, 780/19, 781/11, 781/17, 781/23, 782/18, 782/23
class's 703/25
clause 703/19, 703/20, 703/23, 703/24, 704/7, 705/24, 706/18, 706/19, 706/22, 707/4, 707/10, 708/1, 708/6, 709/16, 709/25, 710/1, 710/11, 711/13, 711/21, 712/24, 713/5, 715/5, 715/13, 715/14, 715/15, 716/21, 716/24, 720/13, 721/23, 722/2, 741/10, 748/24, 757/20, 762/17, 766/5, 770/23, 771/6, 771/18, 773/18, 773/23, 773/24, 779/5, 779/6, 780/16
clauses 773/12
clear 712/20, 713/3, 715/7, 715/10, 717/14, 725/18, 734/4, 734/11
cleared 718/22
clock 723/1
closed 748/3, 750/16
closer 698/19
closure 750/2, 753/1
coal 736/21
Cogen 783/8
combing 738/9
comfortable 744/8, 746/14, 760/16, 760/17
comment 748/14, 748/20
comments
commercial 771/14
Commission 698/21, 698/24, 700/7, 704/10, 704/15, 720/10, 721/13, 721/22, 734/7, 734/15, 736/8, 742/13, 749/10, 749/18, 749/21, 749/23, 750/18, 751/8, 752/9, 752/25, 754/8, 754/25, 756/16, 757/23, 758/25, 760/19, 764/6, 767/17, 767/18, 767/21, 767/24, 768/3, 768/10, 771/4, 772/1, 772/7, 772/14, 777/3, 778/8, 782/2, 782/12, 783/10, 783/17, 784/6
Commission's 701/2
COMMISSIONER 697/4, 697/18, 698/9, 698/14, 698/18, 698/25, 699/4, 699/11, 699/18, 699/22, 699/24, 700/2, 700/5, 700/6, 700/9, 700/14, 700/19, 701/4, 701/5, 701/14, 701/15, 701/18, 701/20, 702/2, 702/5, 702/11, 702/13, 702/25, 704/17, 705/21, 706/1, 706/7, 706/9, 706/11, 706/12, 707/11, 708/3, 708/15, 709/9, 709/22, 710/8, 710/12, 710/23, 712/6, 712/11, 712/18, 713/7, 713/22, 714/2, 714/6, 714/9, 714/16, 715/2, 715/20, 715/22, 716/5, 716/7, 716/19, 717/3, 717/7, 717/20, 719/16, 720/2, 720/14, 720/18, 720/24, 721/5, 721/7, 721/16, 721/24, 723/17, 724/6, 724/11, 725/6, 725/9, 725/13, 726/9, 727/8, 727/15, 727/25, 728/6, 729/8, 729/21, 730/20, 731/7, 731/14, 732/15, 732/22, 733/1, 734/2, 734/17, 735/3, 735/12, 735/21, 736/1, 736/14, 736/20, 737/9, 737/13, 738/14, 738/24, 739/9, 740/5, 741/3, 741/13, 741/18, 741/23, 744/13, 744/20, 745/1, 745/10, 746/1, 746/5, 746/6, 746/7, 746/19, 746/24, 747/3, 747/5, 747/11, 747/19, 747/25, 748/19, 748/21, 749/6, 749/11, 749/14, 749/16, 750/11, 750/21, 750/22, 751/9, 751/17, 751/18, 751/19, 751/22, 751/23, 752/7, 752/10, 752/13, 752/15, 753/3, 753/7, 753/10, 753/13, 753/22, 754/10, 755/2, 755/5, 755/17, 755/25, 756/13, 756/24, 757/1, 757/5, 757/7, 757/10, 757/12, 758/7, 759/13, 759/21, 760/11, 761/9, 761/11, 761/14, 761/21, 762/4, 762/8, 762/14, 762/18, 762/23, 763/3, 763/8, 763/12, 763/19, 764/20, 765/9, 765/10, 765/13, 765/23, 765/24, 766/24, 767/10, 767/12, 767/13, 767/22, 768/13, 768/16, 768/20, 768/24, 769/3, 769/7, 769/8, 769/10, 769/14, 769/17, 769/18, 769/19, 770/4, 770/6, 770/10, 770/12, 770/16, 771/7, 771/8, 771/9, 771/10, 771/20, 771/21, 771/22, 774/2, 774/9, 774/12, 774/17, 775/1, 775/8, 775/13, 775/16, 775/23, 776/2, 776/5, 776/14, 777/7, 778/6, 779/1, 779/8, 779/16, 779/17, 779/19, 780/2, 780/10, 780/19, 780/22, 780/23, 781/3, 781/6, 781/11, 781/17, 781/21, 781/23, 781/25, 782/5, 782/8, 782/11, 782/15, 782/17, 782/23, 782/25, 783/9, 784/3
Commissioners 697/6, 701/23, 703/2, 717/10, 752/5, 753/8, 758/15, 759/1, 760/25, 764/21, 766/3, 769/22, 781/18, 781/20
Commissioners' 780/4
commitment 711/25, 712/5
communication 729/5
companies 702/9, 702/16, 727/9, 727/10, 737/21, 743/5, 758/16
Company 702/1, 718/11, 724/13, 725/12, 733/21, 738/1, 739/10, 770/19, 780/13
company's 723/5, 743/25, 771/15
company-specific 702/24
compare 772/21, 774/3
compared 728/15
compares 705/13
comparison 776/7, 777/4
compensate 773/15
competition 738/3, 738/15
complete 748/17, 750/18
completed 749/1
complicate 761/2
component 703/13, 707/3, 707/7, 707/9, 707/11, 707/21, 707/23, 715/6, 715/8, 715/12, 715/18, 716/22, 716/23, 721/12, 728/24, 775/14
components 776/8
concern 718/3, 741/24, 754/20, 758/8, 764/15, 776/16, 777/7
concerned 747/15
concerns 743/1, 766/8, 766/16
conclude 726/13, 776/20
concluded 779/21, 783/19
concludes 705/20
conditioned 752/8
conditions 759/8
conduct 714/20
conducted 768/5
confess 751/3
conforms 704/1
confronting 742/3
confused 762/5
confusing 722/7
confusion 698/1, 745/5, 745/7
connotation 756/5
conscious 759/15
consideration 755/7
considerations 760/20
consistency 756/12
consistent 757/3, 757/19, 757/22, 762/6, 780/20
constitutes 784/9
contain 707/2
continue 745/8, 746/12, 751/5, 755/21, 756/10
continued 749/22
continues 697/3
contract 772/20, 774/4, 774/7, 774/19, 778/12, 783/7
contracts 776/19
contrary 751/21
contribute 711/1
contribution 703/25, 710/19
conversations 763/11
cooperate 764/13
cooperation 783/16
cooperative 765/7
copies 781/19
core 759/24, 760/4, 766/4
Corp's 704/3, 705/10, 707/5

Corporation 705/6, 706/2, 724/12, 770/20, 780/14
correct 698/13, 699/3, 700/13, 701/13, 702/8, 705/25, 708/13, 708/14, 708/20, 712/17, 713/2, 721/23, 724/17, 728/16, 730/24, 732/19, 768/18, 770/3, 770/10, 781/1, 781/2, 781/9, 781/10
corrected 768/15
correctly 701/8, 746/16, 755/8
cost 703/23, 703/24, 707/2, 708/1, 709/17, 710/19, 710/21, 711/13, 715/13, 719/22, 720/5, 721/1, 723/22, 723/23, 723/24, 731/10, 731/16, 731/17, 732/7, 732/10, 732/14, 739/20, 743/25, 748/24, 757/20, 767/24, 767/25, 768/12, 768/23, 770/22, 772/12, 772/24, 773/2, 773/3, 773/11, 774/5, 774/10, 774/16, 775/4, 778/13, 779/5, 780/16
cost-based 703/24, 718/20, 733/25
cost-effective 777/20
cost-related 711/15
costs 704/2, 705/2, 705/4, 705/12, 709/1, 709/5, 711/15, 711/22, 716/10, 719/19, 720/4, 720/6, 742/22, 768/4, 770/18, 770/25, 771/5, 771/13, 771/17, 780/12
Counsel 698/7, 743/2
counterintuitive 726/23
COUNTY 784/2
couple 717/16, 741/5
course 737/3, 760/18
Court 768/14
Courts 766/18
create 773/17
created 711/14, 715/15, 764/1
credence 756/2
credit 703/18, 703/19, 703/20, 704/3, 705/23, 706/18, 706/19, 707/4, 709/15, 719/1, 741/9, 773/22
credited 703/22, 706/22, 710/22, 712/23, 716/20, 773/15
Crediting 704/6, 773/20
critical 756/15
CSR 784/3, 784/13
cure 781/24
currently 703/17, 705/8, 706/17
customer 730/23
customers 711/9, 719/2, 722/15, 724/25, 734/22, 735/4, 750/8, 750/9, 758/19, 759/6, 776/20, 778/14, 779/22
cycle 700/23

D

data 761/5, 775/6
date 771/15
DATED 784/11
day 723/16, 728/24, 757/17, 757/18, 757/24, 764/10, 765/16, 784/11
days 758/1, 758/3, 759/17, 759/18, 759/20, 761/16, 762/1, 762/2, 762/3, 762/10, 762/12, 764/6, 764/7, 764/17, 764/18, 765/12, 765/18, 765/20
dead 741/11, 741/12
deal 702/5, 702/10, 712/25, 724/2, 728/5, 738/12, 750/3
dealing 714/22, 742/14, 772/8
deals 703/10, 706/15, 717/11, 726/5, 729/7, 738/10
DEASON 697/4, 698/9, 698/14, 698/18, 698/25, 699/4, 699/11, 699/22, 700/6, 701/5, 701/15, 701/20, 702/5, 702/13, 702/25, 706/9, 706/12, 707/11, 708/3, 708/15, 709/22, 710/8, 710/12, 710/23, 712/6, 715/22, 716/5, 717/7, 726/9, 728/6, 729/8, 729/21, 730/20, 731/7, 731/14, 732/15, 732/22, 733/1, 737/9, 737/13, 739/9, 740/5, 741/23, 745/10, 746/5, 746/7, 747/3, 747/11, 747/19, 747/25, 748/19, 749/6, 749/11, 749/14, 749/16, 750/11, 750/21, 751/19, 751/23, 753/13, 753/22, 754/10, 755/5, 756/13, 757/1, 757/7, 757/12, 758/7, 759/13, 760/11, 761/9, 763/3, 763/8, 763/12, 763/19, 764/20, 765/24, 766/24, 767/13, 767/22, 769/8, 769/19, 770/6, 770/10, 770/16, 771/7, 771/10, 771/22, 774/2, 774/9, 774/12, 774/17, 775/1, 775/8, 775/13, 775/16, 775/23, 776/2, 776/5, 776/14, 777/7, 778/6, 779/17, 780/2, 780/10, 780/23, 781/3, 781/6, 781/21, 781/25, 782/5, 782/8, 782/11, 782/15, 782/25, 783/9
debate 713/9
December 749/1, 784/11
decide 751/6, 751/7, 778/8
decided 698/22, 702/9, 702/15, 704/20, 721/14, 721/16
decides 749/10, 749/18
decision 698/23, 699/5, 701/3, 713/4, 733/21, 746/14, 747/16, 751/2, 751/12, 751/20, 752/4, 752/8, 752/17, 756/4, 758/20, 760/18, 766/23, 779/10
decisions 699/6, 758/10, 761/1
decline 723/8, 727/3
declining 723/23
decommissioning 767/4
decremental 731/17
dedicated 722/24, 724/23, 738/9
defer 698/22
define 725/11, 742/19
defining 717/4
definition 717/14, 719/8, 740/13
defraud 733/14
degree 716/4
demand 703/25, 705/5, 708/16, 714/13, 736/24, 738/23
demand-type 709/7
demands 713/21
demonstrate 777/17
demonstrated 750/25
demonstrating 778/10
deny 746/20, 747/5
depend 740/25
depends 735/18, 738/1
deposition 768/7
derived 729/9
describe 748/7
designed 708/1
desire 756/14
determination 714/12, 751/5, 751/6, 778/22
determine 699/1, 729/23, 732/3, 737/1, 737/8, 737/10, 743/24, 772/22
determined 736/12
develop 738/4
development 724/22
dictate 709/6
difference 729/25, 762/19, 776/10, 777/22
differences 703/7
differing 709/22
difficult 709/4, 735/16, 737/14, 737/17, 737/20, 738/16, 753/24, 758/12, 758/15, 760/21
dime 722/17
direction 701/12
disadvantage 745/15
disagree 739/25
disallowance 768/23
disallowing 768/11
disclose 754/22
discovers 713/17
discovery 764/9, 764/10, 764/14, 765/6, 765/7, 768/5, 771/1
discussion 713/8, 752/3, 780/4
disincentive 711/17, 741/19
disparate 718/1, 756/25
disparity 705/16
dispatcher 722/21
disposes 706/13
disposition 701/10
dissatisfaction 760/12
distinction 709/4, 725/14, 777/24, 778/1
divergent 756/6, 756/11
divest 738/20
divide 705/2
divided 723/13, 728/13
divorced 713/3
docket 711/19, 747/8, 749/9, 749/20, 751/14, 751/16, 754/4, 754/24, 762/22, 781/16, 784/5
doesn't 700/20, 715/24, 719/2, 760/2
dollar 735/8
dollars 741/9
driven 735/17, 738/22
driving 739/5, 740/23
Dubin 766/8
during 703/3, 783/1
dynamic 736/10
dynamics 733/15

E

earn 743/3, 743/7
earning 743/2
earnings 723/5
easier 774/24
easily 702/17, 775/6
EBN 718/11
economically 711/5
economics 708/12
economy 704/11, 704/15, 708/22, 708/24, 712/13, 713/13, 714/8, 714/14, 715/6, 716/9, 716/12, 716/20, 716/22, 717/5, 717/12, 717/18, 717/23, 717/25, 718/6, 718/9, 718/16, 718/19, 718/21, 719/3, 719/13, 723/18, 724/8, 725/10, 725/12, 725/14, 725/19, 727/21, 729/10, 734/3, 734/20, 736/9, 737/3, 755/19
ECRC 757/23, 762/7, 762/21, 773/15, 773/23
effect 701/1, 764/1
effective 705/9, 710/4, 751/15
effectuate 746/18
efficiently 739/17
effort 727/3, 764/13
efforts 783/13
eight 730/17, 730/21
Electric 718/11, 719/10, 719/25, 724/13, 725/12, 770/19, 770/25, 771/15, 773/7, 773/13, 773/20, 775/11, 777/6, 779/6, 780/13
Electric's 772/1, 772/6, 774/1
element 716/11, 716/16
eliminate 734/18, 751/15
eliminated 766/1, 766/2, 767/18, 780/6
eliminating 746/20, 751/21
elusive 739/11
emergency 740/19
emission 773/2, 773/14, 773/16, 774/16, 775/25
emphasize 707/22
employ 777/8, 777/23
encourage 755/6
encouraged 714/20
end 731/18, 743/7, 751/13, 751/15, 772/20, 777/17, 779/13
endeavors 783/16
endorse 756/5, 756/25
endorsed 756/18
energy 698/16, 698/20, 703/6, 703/15, 705/15, 706/21, 706/24, 707/20, 707/25, 708/17, 709/2, 709/18, 712/4, 712/16, 712/22, 712/23, 713/17, 727/21, 728/14, 762/6, 770/17, 783/6
energy-based 711/24
energy-related 712/3
energy-type 709/6
engage 737/19, 739/11, 739/23, 765/5, 777/9
engaged 737/18
engages 731/8
ensure 772/19
entered 776/19, 778/12
entity 712/14
environment 731/22
environmental 757/20, 762/7, 762/8, 781/16
equal 773/13
error 763/22
essence 760/15
established 772/7
estimated 758/2, 759/18, 761/25, 762/2, 762/11, 764/19, 765/19
evidence 735/5
evolution 736/15
evolved 722/9
examine 772/21
exception 699/14, 779/9
excess 708/25, 709/10, 714/15, 722/23, 726/4, 743/4
excesses 709/12
excuse 773/11
exhibit 729/12, 749/8, 749/11, 749/14, 772/16
exhibits 749/8
existence 738/1
expand 725/3
expanding 727/4
expands 748/9
expect 756/3
expenses 723/3
experience 774/23
expert 755/10, 755/15
explore 749/19, 749/21
explosion 767/25, 768/10
express 758/7, 760/12
extends 704/11, 745/5
extension 748/1
external 737/24

F

face 752/3
facilitate 748/11
facility 766/10
fact 700/21, 709/4, 712/13, 715/24, 726/17, 729/16, 729/22, 743/22, 746/2, 756/18, 766/7, 776/23, 777/11, 777/14
factor 700/24, 701/8, 704/25, 705/9, 705/11, 706/5, 729/23
factors 699/1, 705/1, 705/17, 736/22, 758/17, 759/6
facts 768/9
fair 743/2, 743/4
fallout 697/18, 697/25, 702/14, 780/6, 780/25
fallouts 702/7, 780/8
falls 698/10, 741/11
Farmland 770/20, 780/14
favorable 728/8
faxed 757/20
FERC 703/11, 717/17, 717/20, 719/20, 721/3, 721/7
figure 769/15
figures 735/2, 773/5, 773/7
file 757/14, 759/3, 762/10, 762/12, 764/2, 765/17, 765/19, 765/20
filed 758/1, 758/3, 758/5, 759/18
filing 759/20, 762/13, 763/24
filings 757/14, 757/17, 758/4, 761/24, 761/25, 764/4, 764/10, 764/18, 765/21
find 738/16, 739/10, 739/14, 763/4, 771/2

fine 702/21, 726/18, 747/18, 753/12
finish 776/14
FIPUG 698/7, 761/14, 761/15, 779/20
firm 711/18, 714/13, 772/11
firmness 707/17, 716/4
five 747/22, 750/1, 770/18, 780/12
fixed 710/19, 710/20, 716/17, 723/12, 724/1, 728/21, 741/15
flexibility 723/15, 728/18, 759/3, 760/13
flexible 728/5, 728/25
flies 752/2
flip 741/21
Florida 697/12, 700/16, 701/25, 702/3, 702/7, 705/6, 706/1, 709/24, 718/7, 718/10, 723/9, 724/12, 725/20, 725/23, 730/25, 731/1, 731/2, 750/6, 750/7, 761/18, 761/23, 762/21, 763/23, 766/9, 766/10, 766/14, 766/21, 768/13, 772/3, 784/1, 784/5
flow 708/1, 711/20, 712/20, 714/24, 719/1, 719/4, 721/22, 724/3, 724/5, 771/17, 773/17, 773/24
flowed 707/9, 708/5, 715/12, 720/13, 722/1
flowing 710/3, 727/13, 730/22, 731/2
fluid 736/10
FMPA 772/22, 774/1, 777/6
folks 746/11
follow 731/12
forecasting 759/12
formula 731/18
found 717/16, 717/18, 717/23, 718/5, 718/7, 719/9, 734/9
four 710/3, 717/18, 717/23, 718/2, 730/22, 750/12
FPC 723/18, 762/19
FPL 698/12, 698/14, 699/15, 700/12, 701/17, 723/18, 724/7, 724/9, 727/13, 727/15, 729/17, 762/19, 762/20, 762/25, 763/4, 766/7, 770/1
FPL's 699/10, 766/3
frame 700/20, 749/4
frames 742/5, 760/16
fraud 740/13
free 703/16
front 777/17, 779/13
fuel 703/20, 704/22, 706/19, 706/22, 708/5, 708/6, 709/16, 709/18, 710/1, 710/3, 710/4, 710/8, 710/10, 710/11, 710/13, 712/24, 716/10, 716/21, 720/8, 721/19, 721/22, 739/20, 741/9, 741/16, 744/19, 745/22, 745/25, 747/17, 748/12, 748/17, 748/23, 750/19, 751/14, 751/15, 752/21, 759/2, 760/7, 762/17, 766/4, 766/5, 767/24, 768/4, 768/12, 768/23, 770/22, 771/2, 771/6, 771/17, 772/24, 773/12, 773/18, 773/24, 774/5, 779/6
function 722/21, 723/12
funded 767/3, 767/6
future 699/6, 752/25, 783/15

G

gain 704/11, 706/21, 707/9, 712/21, 718/25, 719/24, 724/3, 724/5, 728/4, 730/12, 730/14, 730/17, 731/9, 731/19, 732/7, 732/11, 732/21, 733/11, 733/18
gains 703/8, 704/14, 706/16, 706/18, 709/15, 714/24, 717/24, 719/11, 719/12, 727/14, 729/18, 730/9, 732/19, 733/10
game 725/21
gaming 719/5
Gannon 768/1, 768/6, 768/8, 772/25
gas 722/15, 736/21
generated 703/8, 712/21, 772/22, 773/4, 773/21
generation 705/14, 706/6, 709/1, 713/20, 720/11, 722/5, 738/20, 771/16
generation-related 706/16, 706/20, 712/21
generational 703/7
generators 734/23
generic 744/21, 745/24, 746/10, 747/20, 748/6, 748/17, 748/22, 749/20, 751/13, 752/20, 754/4, 754/11, 754/14, 760/15, 766/13, 770/2, 772/8, 777/1, 778/2, 783/14
generically 751/3
glad 778/8
goal 724/16, 757/2
good-faith 764/13
GPIF 741/4, 741/6, 741/10
grant 751/12
greater 725/4, 772/23, 773/4
growing 731/4, 740/7
growth 740/10
guess 700/20, 704/12, 708/3, 708/20, 710/23, 712/25, 714/10, 715/7, 716/8, 716/19, 723/23, 728/11, 729/13, 729/15, 729/23, 738/14, 741/24, 745/6, 745/11, 746/1, 752/18, 754/3, 760/12, 760/21, 776/16, 778/7, 778/18, 783/12
Gulf 697/17, 698/2, 698/4, 703/4, 703/19, 706/19, 709/25, 718/15, 729/13, 730/15, 730/17, 761/19, 761/23, 762/21, 762/25, 763/4, 763/25, 781/18
Gulf's 698/6

H

half 728/23
hammered 740/18
handed 781/19
handle 716/25, 760/19
handled 714/11, 755/20
happy 704/12
hard 733/5, 736/11, 783/13
Hardee 770/21, 780/15
hate 745/15
head 744/17, 760/22
hearings 749/2, 758/23
held 759/10
helped 709/8
helping 760/25
Hernandez 772/16
hidden 713/23
high 739/19, 749/22, 768/11, 768/14
higher 721/11, 743/7
hit 729/3
hold 753/10, 776/21, 776/25
honest 734/16
hope 778/24
hoping 732/17
hour 728/20, 728/23, 733/16
hours 723/16, 728/22
human 724/17, 733/4, 733/6
hurricane 763/23
hybrid 717/1
Hydro 770/20, 780/14
hypothetical 731/24

I

idea 742/18, 743/9, 743/19, 756/5
ideas 743/10
identifiable 707/6, 707/8, 707/23, 715/18
identified 699/14, 699/20, 700/16, 701/21, 707/13, 715/23, 776/9
identify 703/12, 738/11, 774/18
immaterial 704/21, 739/4
immediate 704/5, 704/7
impact 698/2, 735/8
implement 758/17, 759/6
implemented 742/15, 758/11
implications 767/7
implicit 782/17, 782/21
implied 757/15
imprudence 769/2, 769/3, 769/4
in-service 771/14
inappropriate 707/3
incentive 713/4, 713/23, 714/22, 717/12, 718/25, 724/18, 724/20, 724/25, 725/2, 725/3, 726/12, 726/13, 726/16, 731/5, 733/20, 734/18, 735/11, 735/24, 737/5, 738/19, 739/6, 739/10, 739/13, 740/12, 741/19, 742/20, 742/24, 743/6, 743/18, 744/25, 746/21, 754/5, 755/3, 755/24
incentives 714/19, 714/25, 724/15, 726/24, 727/5, 733/2, 739/4, 740/23, 742/17, 744/22, 749/19, 754/5, 755/24
incentivize 714/5, 733/3, 743/16
incorrectly 746/16
increase 727/9, 731/5
increases 727/2, 736/25
incremental 719/22, 723/24, 731/10, 731/16, 732/7, 732/10, 732/14, 743/25, 767/24, 768/3, 772/24, 774/5, 774/18, 774/22, 774/25, 775/3, 775/4, 775/21
independent 754/22
index 736/16
indicate 707/15, 763/17
indicated 711/19, 715/4, 716/9, 761/19, 763/1, 781/12
indicating 765/3
industrial 722/15, 734/22, 735/4
infinitum 756/11
information 732/5, 763/6, 765/5, 766/20, 766/22, 769/5, 774/20, 775/19, 778/17, 778/21, 779/9, 779/25
infrastructure 738/7
inhuman 725/1
initiated 748/22, 748/25
insertion 784/10
institute 755/22
intentionally 733/14
interest 701/11, 733/22, 739/8
interpret 730/5, 733/12, 733/16, 733/21, 752/14, 778/2, 778/3, 778/4, 778/6, 778/9
interpretation 718/5, 756/9
interpreted 717/19, 718/11, 718/15, 730/3, 733/9, 745/12, 745/14, 746/15, 746/16
interpreting 753/19
interrogatories 764/7
interrupt 720/2, 726/9
investigate 716/25, 747/4
investigated 749/20
investigating 718/3, 747/1
investigation 747/20, 748/6, 748/18, 748/23, 750/16, 750/18, 751/13, 754/4, 754/12, 754/14, 754/15, 754/19, 754/24, 755/1, 760/15
investigations 783/14
investment 706/3
IOUs 717/19
IRS 767/7
Issue 696/6, 696/7, 696/8, 696/9, 696/10, 696/11, 696/12, 698/20, 699/9, 699/25, 700/1, 700/10, 700/15, 700/25, 701/10, 702/11, 703/1, 703/3, 703/10, 704/10, 704/13, 704/24, 704/25, 705/20, 706/14, 706/15, 712/19, 713/1, 714/25, 717/4, 717/9, 717/10, 721/19, 721/21, 722/2, 725/15, 734/2, 744/21, 746/20, 747/7, 747/12, 749/4, 749/20, 749/21, 751/2, 751/10, 752/6, 753/1, 754/15, 755/2, 755/18, 756/8, 757/12, 757/13, 759/24, 760/2, 761/10, 766/1, 766/2, 766/3, 766/8, 766/11, 766/13, 768/5, 768/25, 769/23, 771/4, 771/18, 780/6, 780/9, 780/10, 780/11, 780/17, 780/24, 781/2, 782/18, 782/19, 782/20, 783/2, 783/8
issued 749/25
ISSUES 696/3, 696/5, 697/8, 697/13, 697/16, 697/19, 697/25, 698/2, 698/3, 698/5, 698/6, 698/8, 698/10, 698/11, 698/16, 698/23, 699/10, 699/13, 699/20, 700/8, 700/25, 701/17, 701/21, 702/1, 702/6, 702/9, 702/10, 702/14, 702/15, 702/19, 702/20, 702/23, 702/24, 704/16, 713/3, 715/1, 750/20, 753/14, 754/7, 756/3, 756/15, 758/11, 758/13, 760/1, 760/5, 760/6, 780/18, 780/25, 781/1, 781/4, 782/9, 782/18
item 766/18
items 774/5

J

JACOBS 699/24, 700/5, 700/19, 701/4, 701/14, 702/2, 706/11, 709/9, 713/7, 713/22, 714/2, 714/9, 714/16, 715/20, 720/18, 720/24, 721/5, 736/1, 736/14, 736/20, 751/9, 751/18, 751/22, 752/7, 752/13, 755/25, 765/10, 765/23, 767/12, 769/10, 769/14, 769/18, 771/9, 771/21, 779/16, 780/22
January 699/2, 701/2, 710/6, 710/7, 758/11, 771/16, 772/4
Joe 722/23
JOY 784/3, 784/13
jumps 736/20
jurisdiction 705/13, 772/12
jurisdictions 705/3, 705/8
Justification 757/5, 757/7

K

KELLY 784/3, 784/13
key 728/18, 738/11, 756/15
kilowatt-hours 735/15
KIMBERLY 784/3
knit 756/1
known 769/6, 778/11
knows 777/18

L

label 720/5
labeled 716/22
Labor 757/18
Lake 783/8
language 757/21, 761/20, 763/2
larger 733/10
later 698/22, 700/18
latest 739/18
Laughter 747/23, 752/14, 754/18, 755/11
leads 741/24
leave 782/19
leaves 730/20, 752/18
led 768/9
left 725/7, 726/4, 756/8, 780/9, 783/3
leftover 726/2
legal 751/11, 755/6
legitimate 737/1
LEON 784/2
level 707/17, 722/13, 736/11, 736/12, 738/2, 738/4, 738/8, 768/22
levels 743/18, 749/22
leverage 722/16
Light 697/12, 700/16, 703/4, 703/19, 706/17, 709/24, 710/16, 718/8, 730/25, 761/18, 761/23, 763/23, 766/14
likelihood 748/6
limited 728/13, 728/20, 734/3, 734/4
line 739/13, 739/18, 742/23, 742/25, 743/6
lingered 751/4
literal 734/10

little 698/19, 718/3, 721/11, 739/23, 742/4, 762/4, 765/4, 770/13
load 711/4, 712/1, 713/18
lose 761/5
losing 764/22
loss 759/12, 759/14
low 722/14, 722/18
lowest 739/20
lucky 759/1

M

magnitude 748/7, 748/8
main 723/10, 782/20
maintain 755/23
major 742/3
management 769/1
manipulate 739/7
March 772/4
margin 736/5
mark 741/8
market 714/3, 722/11, 724/21, 724/22, 725/3, 727/6, 728/12, 732/1, 734/24, 736/4, 736/10, 736/24, 737/2, 738/4, 738/5, 738/9, 740/8, 740/11, 740/23
market-based 718/20, 730/15, 731/1, 731/8, 734/14
market-based-based 726/20, 731/23, 733/24
marketed-based 723/18
marketing 726/1, 738/2, 742/13, 742/22
marketplace 723/14, 734/13
match 726/6, 726/17, 729/4
material 746/4
mathematical 723/12
matter 700/20, 709/3, 719/2, 747/13, 752/18, 756/7, 758/12, 766/7, 783/6
matters 745/24, 748/11, 758/16, 781/9
maximize 726/19, 733/9, 737/21, 737/25
maximum 733/7, 740/9
meaningful 765/5
mechanism 723/11
meet 714/13, 714/14, 715/25
meeting 713/21
memory 763/14
mentioned 716/15
merit 756/21, 756/22
method 704/1
methodology 718/14
METZKE 784/4
microphone 698/18, 767/22
million 769/11
mind 712/2, 747/21, 747/23
minute 720/3, 769/23
minutes 747/22
mirrors 771/19, 780/17
miss. You're 729/3
missed 700/1
misses 741/8
mode 748/2
modification 773/9, 773/10, 773/19, 774/3, 778/18, 779/2, 779/3
modifications 772/7, 773/25
modified 776/6
modify 751/10
Monday 776/16
money 739/16
month 752/25, 761/5, 768/8
morning 776/17
motion 699/19, 699/21, 701/16, 706/8, 706/9, 706/13, 712/24, 715/3, 715/21, 716/6, 716/8, 717/7, 769/25, 771/7
move 700/15, 702/3, 702/4, 702/19, 702/23, 716/20, 716/23, 746/19, 755/18, 765/9, 767/10, 769/17, 771/8, 771/20, 779/8, 780/19, 780/20
moved 700/6, 701/15, 706/12, 765/24, 767/13, 769/19, 771/10, 771/22, 779/17, 780/23, 782/17, 782/22, 782/24
MR. BALLINGER 717/3, 717/10, 717/22, 719/18, 720/7, 720/16, 720/22, 721/2, 721/6, 721/9, 721/18, 722/1, 723/20, 724/9, 724/12, 725/8, 725/11, 725/15, 726/22, 727/12, 727/17, 728/3, 728/17, 729/11, 730/1, 730/24, 731/12, 732/13, 732/17, 732/24, 733/19, 734/6, 734/21, 735/7, 735/14, 735/23, 736/7, 736/18, 737/7, 737/11, 737/23, 738/18, 739/2, 739/25, 740/17, 741/5, 741/15, 741/20, 744/15, 744/23, 746/23, 746/25, 747/6, 747/15, 747/21, 752/16, 752/22, 753/5, 753/9, 753/12, 753/18, 754/2, 757/11
MR. BOHRMANN 698/16, 698/20, 699/3, 699/8, 700/13, 757/13, 759/7, 759/15, 761/8, 761/13, 761/15, 761/18, 761/22, 762/7, 762/9, 762/15, 762/20, 762/25, 763/5, 763/10, 763/16, 763/21, 765/15, 767/20, 767/23, 768/15, 768/21, 769/1, 769/4, 769/16, 770/17, 771/13, 771/25, 774/8, 774/11, 774/14, 774/23, 775/5, 775/11, 775/15, 775/22, 775/25, 776/4, 776/11, 777/1, 777/25, 778/24, 779/3, 779/24, 780/11, 780/21
Mr. Chairman 699/18, 706/8, 712/18, 715/2, 745/2, 749/7, 752/15, 755/17, 759/21, 779/12
Mr. Childs 754/11, 754/17, 755/9, 755/12, 755/14, 782/13, 782/15, 782/16, 783/2
Mr. Elias 748/13, 752/1, 755/6
MR. HERNANDEZ 776/12
Mr. Howell 704/18, 724/16, 735/16
MR. KEATING 697/6, 697/22, 698/4, 698/13, 699/16, 700/24, 701/13, 701/23, 702/22, 748/15, 755/6, 761/23, 768/18, 768/19, 769/13, 780/8, 781/2, 781/4, 781/10, 781/15, 782/4, 782/5, 782/7, 782/10, 782/13, 783/4
Mr. McWhirter 749/6, 749/7, 749/13, 749/15, 749/18, 750/14, 761/17
MR. STONE 697/15, 697/20, 698/1, 748/21, 781/18
Mr. Wade 766/17
MR. WHEELER 707/14, 708/20, 709/17, 710/2, 710/7, 710/9, 710/18, 711/12, 712/9, 712/17, 713/2, 713/14, 714/1, 714/10, 714/21, 715/9, 716/1, 716/13, 717/2
Mr. Wieland 716/15
MR. WILLIS 750/15
MS. DRAPER 703/2, 704/23, 705/25, 706/4, 706/15, 708/14, 709/13, 709/24, 710/6, 710/10, 710/15
Ms. Harlow's 722/10, 729/11
MS. LEE 766/3, 767/5, 769/22, 770/8, 770/11, 770/15
Municipal 772/3

N

NANCY 784/4
nation 723/2
native 713/18
natural 722/15
nature 724/17, 726/21, 733/4, 733/6
necessary 743/24, 760/23, 763/20
need 702/18, 711/7, 713/17, 714/11, 717/13, 718/18, 725/3, 726/16, 726/24, 727/6, 729/2, 742/16, 742/19, 742/21, 742/23, 743/10, 743/13, 743/20, 743/21, 744/5, 744/10, 746/17, 747/4, 750/13, 755/15, 756/15, 758/19, 758/22, 758/24, 763/9, 763/12, 778/4
needed 711/3, 712/1, 732/5, 740/21
needs 715/25, 722/24, 728/24, 730/5, 756/16
negotiated 723/14, 728/12
negotiations 726/20
net 727/21, 759/14, 777/11, 778/3, 778/10, 779/25
network 712/23, 718/10, 718/11, 721/21, 723/25, 725/21, 734/3
new 760/2
nickel 722/17
no-brainer 725/25, 726/16
non-fallout 702/19
non-stipulated
nonbroker 703/5, 706/21, 722/2, 726/14, 729/10
nonfirm 703/5, 706/21, 707/1, 709/14, 713/15, 716/3
nonfirm-type 707/19, 713/15
nonissue 778/23
nonroutine 758/13
nonseparated 712/22, 719/3
nonseparated-type 707/16
note 779/19
notes 784/9
notice 734/21, 758/18, 759/6
November 749/2, 754/9, 758/2, 758/10, 758/24, 761/3, 761/4, 764/5
nuclear 766/4, 766/9, 767/4
number 727/23, 729/16, 729/17, 729/19, 733/11
numbers 697/21, 697/23, 701/6, 701/7, 769/10, 769/11, 776/23, 778/20, 778/23, 780/7, 781/12, 782/2

O

O&M 773/3, 775/15, 775/17, 775/18
objected 754/25
objecting 762/23
objection 763/13, 763/18, 766/24
objectionable 763/4
obligation 711/21
obtained 713/9, 740/9
October 764/4, 771/16
Off-system 722/18, 722/20, 724/24, 726/19, 727/17, 727/18, 727/19, 749/22, 777/10
office 747/13
Okeelanta 770/19, 780/13
open 747/8, 747/23, 754/3, 754/11, 754/19, 754/21, 754/23
operate 739/17
operating 703/18, 704/4, 758/8, 763/22, 773/8
opinion 730/2, 740/25, 749/5
opportunity 723/2, 723/20, 731/2, 749/24, 750/3, 752/22, 759/8, 767/1
opporutunity 752/5
oppose 770/24
opposed 709/6, 712/5, 726/15, 728/12, 729/18, 730/21, 730/23, 761/4, 775/21, 778/16
option 752/18
order 697/5, 697/14, 702/21, 703/11, 709/19, 711/18, 717/17, 718/8, 718/12, 718/15, 719/20, 721/7, 725/17, 734/4, 734/10, 734/11, 740/20, 746/22, 749/25, 756/4, 756/8, 756/14, 757/16, 772/10, 772/13, 772/19, 778/1, 781/7
Orders 766/16, 766/17
original 719/19, 720/10, 722/4, 725/17, 730/8
originally 721/3, 779/7
OS 724/1, 724/3, 727/20, 727/23, 728/22, 729/17
ostensibly 713/10
outcome 699/5
outstanding 699/9
overwhelming 735/8

P

p.m 783/20
PAA 747/12, 753/4, 753/5, 754/16, 755/2
pages 784/9
panel 742/6, 752/4
pardon 749/13
part 715/14, 715/23, 719/23, 720/6, 720/15, 723/3, 730/4, 741/10, 778/17
parties 699/7, 748/3, 748/5, 757/21, 760/24, 763/1, 764/1, 764/6, 764/12, 765/6, 783/12
parties' 756/22
Partners 770/20, 770/21, 780/14, 780/15
party 762/22
passed 734/12
pay 711/22, 735/18, 741/2
paying 708/18, 711/2, 711/5
payment 783/7
payments 698/17, 698/21
peak 703/25, 708/25, 709/7, 711/1, 711/2, 711/4, 711/6, 712/1, 713/21, 714/13
peaks 708/23, 714/15
penalize 737/20, 777/15
penalized 741/8
penalty 741/6, 741/12, 741/21
pending 751/12
percentage 735/1
period 729/20, 745/23, 745/25, 748/10, 753/24, 754/1, 756/17, 783/1
peripheral 722/21
permissible 748/4
permitted 705/18
perpetuate 745/16
personnel 722/25, 724/23, 726/1
perspective 708/21, 730/8
perverse 739/7
phone 723/1, 726/3, 763/10
pick 744/5
picture 714/23, 742/2
place 708/13, 712/7, 738/7, 740/15, 752/20, 769/6, 772/18, 784/6
places 758/14
plan 707/1, 708/8, 710/25, 713/19, 714/12, 714/13, 714/14
planned 708/10
planning 713/21
Plant 708/23, 710/20, 711/3, 711/15, 711/25, 712/7, 715/24, 740/4, 768/8
plants 710/21
pleading 764/2, 764/3
pleasure 765/8
plus 723/13, 728/13, 743/17
PODs 764/7
point 697/6, 699/12, 702/18, 704/12, 707/7, 709/13, 710/24, 713/8, 714/21, 725/23, 734/11, 737/4, 748/3, 749/5, 751/6, 778/19, 782/1
pointed 722/11, 735/16
policy 742/4, 742/15, 745/4, 745/5, 752/4, 760/19, 768/10, 772/8, 777/1, 778/2
Polk 771/15
portion 775/18
position 704/9, 715/10, 756/19, 758/5, 764/11, 770/24, 772/6, 775/9, 775/12, 775/23, 779/23, 780/17
positions 698/6
positive 777/11
possibilities 728/14
possibility 714/10, 747/17, 767/2
possible 702/17, 722/18, 739/15, 739/20, 764/13
post 726/17
Power 697/12, 700/16, 703/4, 703/16, 703/17, 703/18, 704/3, 704/9, 704/13, 704/24, 705/6, 705/10, 705/17, 706/1, 706/17, 707/5, 709/24, 709/25, 710/3, 710/16, 711/18, 718/7, 718/8, 718/15, 724/12, 730/25, 738/13, 761/18, 761/19, 761/23, 762/22, 763/23, 763/25, 766/9, 766/10, 766/14, 766/21, 767/25, 770/18, 770/20,

770/21, 770/22, 772/2, 772/3, 780/12, 780/14, 780/15, 783/7
precision 759/12, 764/22
preclude 746/25
predict 736/11
predominance 731/23
predominant 724/14, 727/20, 727/23, 729/17, 734/12
predominantly 724/7, 724/10, 727/16
preference 742/9, 747/10
prefiled 784/10
Prehearing 697/14, 757/16, 757/19, 764/5, 764/11
preliminary 783/6
premise 708/4, 709/9
premises 709/11
prepared 744/11, 745/16
prescribed 784/10
pressure 722/13, 758/19
pressures 725/4, 737/24
pretty 713/3
prevailing 736/4
price 721/11, 728/11, 728/12, 728/21, 730/11, 730/16, 732/21, 736/4, 736/21, 750/8
priced 720/17
prices 721/8, 722/15
pricing 723/14
problem 716/8, 717/15, 730/4, 760/10
problems 717/4
proceed 699/12, 782/1
proceeding 704/2, 742/5, 744/21, 744/23, 748/13, 749/23, 750/19, 752/20, 754/12, 754/13, 754/22, 755/22, 758/9, 770/1, 770/2, 782/24
proceedings 784/8, 784/10
process 714/12, 714/17, 764/16
product 712/3, 728/19
production 723/24
profit 738/25
projected 757/17, 761/24, 762/3
projection 736/9, 756/17, 757/14, 758/4, 759/19, 762/13, 764/18, 765/21
projections 761/7, 764/23
proposed 757/21, 762/5, 772/1, 773/13, 779/6
proposes 773/19
proposing 740/19, 754/23, 762/16
protections 714/18
prove 777/13
proved 769/4
provide 704/4, 704/7, 765/7
prudent 770/21, 777/20, 780/15
Public 698/7, 701/25, 702/3, 702/8, 743/1, 784/5
pulled 736/8
purchase 711/18, 712/16, 718/18, 730/11
purchased 767/25, 770/18, 770/22, 780/12
purchases 709/15, 709/16, 709/18, 722/19
purchasing 728/7
pure 722/6
pursue 724/17, 735/13, 738/21, 738/25, 755/1, 777/17, 777/21
pursued 734/19, 734/23, 737/12, 746/3
pursuing 724/24, 725/1, 727/1, 735/5
pushed 763/24
put 713/10, 726/5, 767/3

Q

qualify 742/20
quarterbacking 776/17
question 704/17, 708/4, 713/5, 713/22, 714/17, 715/22, 720/25, 723/17, 724/7, 729/21, 731/13, 734/18, 742/11, 742/16, 745/6, 748/5, 748/16, 751/25, 754/11, 754/18, 756/20, 760/3, 774/2, 775/17, 776/13
questions 742/8, 742/21, 744/10, 753/25, 755/7, 771/7
quote 731/16
quoted 721/8
quotes 731/15, 749/8
quoting 728/10

R

raise 771/4
raised 703/2, 718/2, 750/20, 756/3, 756/8
raising 750/8
range 743/8
ranges 743/5
rate 700/22, 704/2, 704/6, 711/16, 714/7, 720/6, 723/6, 728/8, 743/2, 743/4, 766/18
ratepayer 740/16, 772/15, 777/4, 778/3, 778/10, 779/25
ratepayers 703/22, 704/5, 706/22, 708/2, 710/20, 719/5, 724/4, 731/20, 739/21, 740/3, 772/17, 772/19, 773/5, 773/15, 776/9, 777/5, 777/20
rates 704/8, 708/19, 722/14, 722/18, 723/7, 726/20, 734/14, 736/9
rational 733/21
reach 755/22, 764/21
read 753/8
reading 734/10, 778/1
reason 697/23, 698/24, 708/7, 710/13, 710/15, 710/17, 715/15, 716/14, 716/18, 722/3, 723/10, 725/2, 736/8, 750/17, 760/3, 771/2
reasonable 748/15, 776/19, 777/19, 778/13
reasons 718/24
recalculation 701/6
recalculations 781/8
recall 713/18
recallable 711/25, 713/16
recalled 712/2
received 703/5, 764/4, 764/10
recess 781/22, 781/24
recommend 712/19
recommendation 705/22, 715/4, 717/11, 747/9, 751/10, 752/24, 758/21, 759/4, 759/9, 759/14, 759/17, 765/14, 765/25, 767/14, 769/9, 769/20, 771/11, 771/18, 771/23, 776/6, 780/3, 780/24
recommendations 765/1
recommended 704/19, 718/25, 757/16
recommending 722/8, 762/16, 762/24
recommends 703/21, 706/20, 749/19, 768/2
record 742/7, 748/2, 749/12, 752/23, 753/6, 763/6, 763/9, 763/13, 763/14, 763/15, 763/17
recover 709/15, 709/17, 711/14
recovered 723/7, 771/6
recovering 770/25
recovery 703/23, 703/24, 708/1, 711/13, 715/13, 745/25, 748/24, 753/23, 754/1, 756/17, 757/20, 766/4, 767/2, 770/1, 770/5, 770/7, 770/8, 770/22, 770/23, 772/15, 779/5, 780/16, 783/1
recurring 714/3
reduce 711/21
reduction 704/7
refresh 763/14
region 714/4, 723/19, 723/21
regular 747/9
regulatory 772/2
rejected 756/19
related 705/1, 705/4, 705/12, 705/14, 707/23, 709/5
relates 699/15, 701/17
relevance 750/24, 751/1
rely 746/2
relying 761/6
remain 697/25, 698/2, 701/1, 745/7, 755/20
remaining 773/24, 780/25
remove 711/17, 717/11, 718/25
renaming 719/23
repeat 765/13
replacement 767/24, 768/4, 768/11
reported 784/7
REPORTERS 784/1, 784/4
Reporting 784/3
reports 723/4
representatives 763/11
request 766/4
requested 761/24
require 701/5
required 703/12, 708/17, 717/17, 717/20, 720/4
requires 727/3
reservation 707/18, 716/2, 716/17
reserve 767/3, 767/6
residential 713/11
resolution 697/25, 755/23
resolved 748/12, 754/8, 756/4, 756/9, 756/16, 758/16
respect 700/9, 701/19, 702/2, 746/20, 752/3, 760/5, 779/10
respond 738/6, 764/7
response 783/11
responses 764/14, 765/7
responsibility 705/5
responsible 776/25
restrictive 723/11
resubmit 781/12
results 705/11, 706/23
retail 703/22, 704/5, 704/8, 705/3, 713/10, 713/11, 714/7, 719/1, 722/13, 738/3, 772/11, 778/14
return 743/3, 743/4
revenue 704/19, 705/23, 710/21, 712/3, 735/1, 773/6, 775/4, 779/4
revenues 703/5, 703/8, 703/11, 703/18, 703/22, 704/4, 704/6, 705/1, 705/2, 705/7, 705/12, 705/19, 705/22, 706/19, 707/4, 708/2, 711/20, 715/12, 717/18, 719/4, 719/11, 719/14, 721/14, 721/20, 735/9, 772/21, 772/23, 773/4, 773/8, 773/11, 773/21, 773/22, 773/24, 774/4, 776/7
review 742/11, 742/16, 743/23, 764/25, 765/5
reviewing 737/16
revise 700/22
revised 704/9, 781/19
revision 700/22
revisited 700/17
reward 741/6, 741/12, 742/24
rid 722/8
rise 768/22
robust 724/21
room 763/22
rose 744/17
round 764/9
route 739/3, 747/16
routine 744/4, 758/12, 759/25, 760/1
RPR 784/3, 784/4, 784/13
rule 754/12, 754/13, 754/22
ruled 721/22
running 768/7

S

safeguards 714/18
sale 708/24, 709/5, 712/4, 712/6, 712/10, 713/19, 715/6, 715/8, 716/3, 716/12, 718/6, 718/12, 718/16, 718/19, 718/21, 719/3, 719/22, 723/12, 727/22, 730/10, 737/12, 772/10, 772/18, 772/22, 773/1, 773/16, 773/22, 774/1, 779/5
sales 703/6, 703/9, 703/13, 703/14, 704/11, 704/15, 706/21, 706/24, 707/1, 707/2, 707/6, 707/9, 707/23, 708/22, 712/13, 712/22, 713/13, 713/20, 713/25, 714/8, 715/11, 716/9, 716/20, 716/22, 717/1, 717/5, 717/12, 717/18, 717/21, 717/25, 718/9, 718/20, 719/3, 719/13, 721/20, 722/3, 722/18, 722/20, 723/2, 723/19, 723/21, 724/8, 724/24, 725/1, 725/10, 725/12, 725/14, 725/19, 726/14, 726/15, 726/19, 726/24, 727/1, 727/2, 727/5, 727/9, 727/18, 727/19, 727/23, 729/16, 729/17, 731/1, 731/2, 731/3, 731/4, 733/25, 734/1, 734/4, 734/5, 734/20, 734/25, 736/9, 737/3, 737/25, 738/16, 738/17, 738/21, 739/5, 740/2, 740/6, 740/24, 743/15, 749/22, 750/5, 755/19, 772/8, 777/2, 777/10
sample 744/7
sat 735/11
satisfactory 759/23
satisfy 744/7
savings 727/10, 729/5, 729/9
saw 697/20
schedule 749/4, 758/8
schedules 781/19
scraping 722/17
second 699/22, 700/5, 700/19, 701/14, 706/10, 706/11, 710/17, 715/20, 716/6, 717/8, 726/10, 765/23, 767/12, 769/18, 769/19, 771/9, 771/21, 773/10, 774/9, 779/1, 779/3, 779/16, 779/18, 780/22
seconded 700/7, 701/16, 706/12, 765/24, 767/13, 771/10, 771/23, 780/23
seek 737/2
seeking 770/1
self-generation 722/16
self-service 734/23
sell 714/8, 721/11, 724/1, 724/2, 728/12, 732/2, 738/12
seller 718/17, 724/7, 724/14, 728/1, 740/22
sellers 728/11, 736/6
selling 709/21, 712/14, 713/17, 731/15, 731/19, 731/25, 732/1
send 764/9
sending 777/9
sense 712/2, 745/11, 761/12
sentence 778/3
separate 699/21, 705/7, 720/12, 747/8, 754/3, 772/9, 774/5, 777/2, 782/24
separated 705/4, 744/21, 772/11, 779/15
separately 703/12, 720/13
separation 704/25, 705/1, 705/9, 705/10, 705/17, 706/2, 706/3, 706/5, 706/6
September 757/18, 763/24
sequence 697/3
serve 708/11, 708/16, 708/17, 708/23, 711/1, 711/4, 711/21, 712/1, 713/18, 713/20, 714/13, 773/1, 774/6, 774/19
served 710/19
Service 784/5
serving 777/6
set 722/4, 741/11, 746/21, 747/13, 761/3, 768/10, 768/14, 768/16, 768/25, 777/2, 778/1
share 739/23, 778/9
shareholder 742/24, 743/5, 746/21
shareholders 729/24
shift 742/4
short 713/12, 713/14, 735/19, 742/5, 781/22, 781/23
short-term 719/4, 734/25, 736/24, 737/25
shortfall 773/8
Show 700/7, 701/16, 706/13, 717/8, 765/25, 767/14, 769/20, 771/11, 771/23, 778/20, 779/18, 780/2, 780/24
shows 779/25
side 714/22, 721/11, 741/21, 741/22
sides 743/12

signal 777/9
simple 702/17, 731/24
sitting 760/9, 760/25
situation 708/25, 733/8, 758/15
situations 736/23
six-month 748/24
skills 738/5
small 729/19, 735/1
smoother 728/25
SO2 773/2, 773/14, 774/10
sold 711/8, 732/8, 744/1
sort 701/12, 716/8, 716/25, 741/13, 753/25, 756/23, 783/15
source 763/17
spectrum 718/21
spin 760/14, 766/13
spinning 766/25
split 712/25, 720/4, 728/13, 731/19, 734/3, 744/14, 750/24
split-the-savings 718/9, 718/12, 718/14, 719/13, 720/11, 722/6, 723/10, 725/20, 730/10
split-the-savings-the-savings 745/8
splitting 720/1, 727/10
Staff 697/16, 698/5, 699/11, 699/20, 701/7, 701/22, 703/2, 703/21, 704/10, 704/13, 705/16, 706/20, 712/19, 715/10, 716/24, 718/24, 720/9, 729/8, 737/23, 738/9, 746/20, 748/4, 749/19, 752/23, 754/3, 755/21, 757/16, 757/20, 759/3, 759/8, 760/24, 762/5, 762/15, 762/16, 763/19, 764/15, 764/24, 765/2, 765/3, 765/9, 765/11, 765/13, 767/10, 768/2, 768/5, 768/21, 769/17, 769/20, 771/8, 771/20, 772/5, 773/19, 773/20, 773/25, 774/21, 775/20, 776/15, 779/8, 780/19, 780/20, 781/6, 781/7, 781/13, 781/25
Staff's 702/20, 705/21, 708/4, 708/21, 715/4, 717/11, 718/2, 719/21, 742/1, 756/18, 756/21, 760/22, 767/14, 771/11, 771/23, 773/9, 780/3, 780/24
stand 740/19, 768/15
standard 768/11, 768/14, 768/17, 768/24, 776/18, 776/21, 777/8, 777/22, 778/15
stands 764/3
start 734/22
started 718/3
starting 699/2
state 710/12, 717/15, 750/5, 750/6, 784/1
states 772/10, 777/2
status 742/10, 745/23, 753/23, 755/21
statute 754/20
stay 745/9
stenographically 784/7
stipulate 698/5, 698/7, 761/17
Stipulated 696/5, 697/8, 697/11, 697/13, 697/17, 697/24, 698/4, 698/12, 699/13, 700/7, 701/21, 701/25
stipulation 698/15, 701/24, 702/4, 757/21, 761/12
stipulations 699/19, 701/19
stockholders 719/7, 719/15, 730/12, 731/20
strikes 716/10
structure 723/15, 724/2, 728/22, 738/12, 742/18, 755/7
structures 724/23
struggling 717/6
subject 750/3
submitted 701/6
substantive 702/6
suffice 775/20
sufficient 782/3, 782/6, 782/7
suit 730/5
sum 772/23, 773/5, 773/7, 776/8
summary 705/20
summer 714/4
Sunset 751/17, 751/18, 752/7, 752/11
superior 774/21
supply 772/2
supporting 710/20, 740/3
Supreme 768/14
surplus 749/22
surveillance 723/4
swing 735/10
switch 710/13
switched 710/4
symmetry 709/20
system 719/6, 719/19, 720/15, 720/20, 722/4, 722/6, 725/24, 726/2, 727/22, 728/2, 732/18, 734/12, 740/20, 750/25, 772/12, 773/1, 773/2, 773/14, 774/10, 774/13, 774/15, 774/21, 774/24, 775/9, 775/13, 775/15, 775/16, 775/18, 776/3
systemic 769/1

T

tag 736/15
tailor-make 728/19, 729/2
talk 725/16, 733/1, 739/4, 743/10, 743/20, 743/21, 750/10
talked 726/3, 744/16, 744/17, 763/5
talking 707/15, 707/19, 714/23, 721/3, 725/9
talks 778/10
Tampa 718/11, 719/10, 719/25, 724/13, 725/12, 770/19, 770/25, 771/15, 772/1, 772/5, 772/21, 773/7, 773/13, 773/20, 774/1, 775/11, 777/6, 779/6, 780/13
target 741/11
targeted 741/8
tariff 727/23
tariffs 724/22
technology 722/14, 729/6, 739/18
TECO 703/4, 703/20, 706/18, 709/25, 776/9, 776/18
TECO's 774/15, 775/8, 775/23
ten 737/17, 759/20, 764/17
term 713/12, 713/14, 725/19, 772/10
terms 713/21, 714/12, 714/25
testifying 750/9
testimonies 757/15
testimony 706/25, 710/18, 716/15, 722/10, 733/2, 744/16, 744/25, 750/1, 765/21, 766/6, 784/10
testing 738/5
Thank 757/11, 770/11, 770/15, 783/12
theoretically 775/2
Thereupon 783/19
they've 735/11, 739/17, 739/18, 739/19, 763/5
third 775/14
three 710/2, 723/16, 728/22, 748/9, 773/5, 773/7, 774/4, 776/8
threshold 736/12
threw 744/16
throw 728/23
thrown 726/7
thrust 704/24
tight 714/3
tilted 765/4
time 698/22, 700/18, 700/20, 700/23, 708/12, 711/7, 712/9, 718/1, 718/23, 722/9, 722/22, 725/20, 728/21, 737/15, 740/19, 740/20, 741/16, 742/5, 744/15, 744/24, 745/16, 747/5, 748/10, 748/12, 748/16, 749/1, 749/4, 749/21, 758/21, 759/5, 760/5, 760/6, 760/16, 760/23, 760/24, 761/2, 764/2, 764/8, 764/16, 764/24, 765/4, 766/20, 768/6, 770/9, 771/5, 776/18, 776/22, 777/19, 778/12, 778/22, 781/22, 782/12, 783/10, 783/18, 784/6
times 732/4, 737/17, 748/9
Tom 720/2, 734/17, 738/14, 741/3, 744/13
tool 722/16
tools 722/19
touch 729/6
toured 768/8
town 725/21
track 735/14, 774/24, 774/25, 775/6
trade-off 759/16
transaction 711/24, 726/18, 729/22, 730/11, 730/16, 731/11, 732/3, 732/6, 732/21, 737/18, 739/14, 740/21, 777/20, 778/14, 779/21
transactions 707/15, 707/16, 707/20, 708/9, 708/11, 708/17, 709/10, 709/11, 711/23, 713/15, 715/17, 716/16, 720/22, 720/25, 729/10, 731/8, 731/24, 733/8, 737/16, 737/22, 739/12, 739/24, 740/15, 742/20, 743/23, 744/5, 753/15
transcribed 784/8
Transcript 697/3, 784/8
transcription 784/9
transfers 750/7
transition 729/1
transmission 703/8, 703/10, 703/13, 703/16, 703/17, 703/21, 704/2, 705/1, 705/4, 705/7, 705/9, 705/12, 705/18, 705/22, 706/3, 706/5, 717/17, 719/11, 719/14, 719/19, 719/22, 719/24, 720/5, 720/6, 720/12, 720/19, 721/1, 721/12, 721/14, 721/20, 722/4, 744/17, 744/18, 773/21, 779/4
transmission-related 705/10
treat 703/5, 721/14, 721/17
treated 745/7, 753/15, 753/16, 757/8
treatment 703/7, 704/3, 709/20, 709/23, 713/5, 718/1, 744/18, 756/25, 757/3, 772/2, 772/18, 773/23, 774/1, 777/3
treatments 746/8
treats 703/17
trend 714/2
true 750/15, 784/9
true-up 701/11, 757/25, 758/2, 759/18, 761/25, 762/11, 764/19, 765/17, 765/19
true-ups 699/7
turn 748/22
two 705/8, 723/15, 743/12, 748/9, 752/25, 772/6
type 712/3, 715/17, 732/2, 737/22, 742/18, 743/10, 743/13, 744/4, 757/4, 768/25, 775/21
types 703/14, 707/22, 708/1, 711/23, 713/20, 715/11, 715/16, 727/2, 727/9, 768/17

U

unaddressed 783/3
unanimously 700/8, 706/13, 717/8, 765/25, 769/21, 771/12, 771/24, 780/4
unanswered 742/8
unbundled 720/12
unbundling 717/17, 717/21, 720/9
uncomfortable 742/4, 745/3
unfairness 745/11
uniform 749/24
Unit 768/1, 768/6, 771/15, 771/16, 772/24
units 774/6
utilities 697/12, 701/25, 702/3, 703/11, 703/15, 706/25, 708/8, 709/14, 709/23, 711/14, 717/23, 718/2, 718/7, 722/13, 722/16, 723/13, 726/25, 730/3, 745/12, 753/15, 757/14, 759/5, 759/11, 765/16, 765/18, 765/20, 777/9, 777/16
utility 709/2, 710/25, 712/1, 712/4, 713/17, 724/20, 725/1, 725/25, 731/7, 731/15, 731/17, 731/19, 731/25, 741/7, 745/17, 745/18, 746/15, 750/7
utility's 714/12
utilized 711/4, 774/6

V

variable 773/3, 775/15, 775/17, 775/18
verify 743/25, 744/6
view 748/5, 758/22
viewed 718/8
views 756/6
vigor 727/1
vigorously 734/19, 738/21, 739/1
Volume 697/3
Volumes 784/9
vote 697/7, 747/7, 751/14, 769/25
voted 781/5, 782/22

W

Wade 766/7
wait 702/14, 748/14
warranted 759/8
wastecan 726/7
water 721/13
week 763/24
weights 773/1
welcome 748/20
wholesale 703/6, 703/13, 705/3, 705/13, 706/21, 709/14, 712/22, 724/21, 738/2, 738/8, 772/2, 772/8, 772/10, 772/18, 772/20, 774/1, 777/2
Wieland 707/14
willing 700/15, 716/19, 718/16, 718/17, 735/18, 735/25, 740/21, 740/22, 741/1, 753/21, 778/19
wish 699/12, 699/17
withdrawn 767/16, 767/17
witness 707/5, 707/14, 740/18, 766/7, 766/8, 768/7, 772/16
witnesses 712/12, 784/10
words 707/16, 707/24, 713/16, 719/12, 723/22, 741/7, 751/14, 755/20
wordsmithing 756/7
work 726/25, 733/3, 739/21, 760/2, 760/17, 783/13
worked 724/20, 731/21
working 725/4, 726/1, 738/5
works 731/21, 760/1
world 735/24, 740/24
worry 719/7
writing 699/25
written 747/9, 752/24, 758/21, 759/3, 759/9
wrong 711/10, 745/18, 770/12, 770/13

X

X 696/2, 743/15, 743/16, 745/17, 778/20

Y

year 703/4, 720/8, 748/25, 749/1, 749/3, 750/19, 755/9, 755/13, 755/16, 757/25, 758/2, 758/4, 759/11, 759/19, 762/11, 763/22, 763/25, 764/3, 765/18, 765/19, 765/22
years 717/16, 728/15, 734/9, 738/8, 750/1, 750/12

Z

zero 719/19, 720/17, 721/3, 722/5, 763/22

APPENDIX I

FUEL COST RECOVERY

FORECAST ASSUMPTIONS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 1
COMPANY/ FPL
WITNESS: R. Silva
DATE: 11-22-99

RS-1
DOCKET NO. 990001-EI
FPL WITNESS: R. SILVA
EXHIBIT_____
PAGES 1-13
OCTOBER 1, 1999

APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS

TABLE OF CONTENTS

PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs - Heavy Oil (BASE CASE)	R. Silva
4	Projected Dispatch Costs - Light Oil (BASE CASE)	R. Silva
5	Projected Dispatch Costs - Solid Fuels	R. Silva
6	Projected Natural Gas Price & Availability (BASE CASE)	R. Silva
7	Projected Dispatch Costs - Heavy Oil (LOW CASE)	R. Silva
8	Projected Dispatch Costs - Light Oil (LOW CASE)	R. Silva
9	Projected Natural Gas Price & Availability (LOW CASE)	R. Silva
10	Projected Dispatch Costs - Heavy Oil (HIGH CASE)	R. Silva
11	Projected Dispatch Costs - Light Oil (HIGH CASE)	R. Silva
12	Projected Natural Gas Price & Availability (HIGH CASE)	R. Silva
13	Projected Unit Availabilities and Outage Schedules	R. Silva

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

BASE CASE

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$15.79	$15.30	$14.78	$16.19	$16.29	$16.16	$16.09	$15.17	$15.26	$16.70	$16.14	$15.12
1.0% SULFUR	$14.63	$14.27	$13.76	$15.19	$15.02	$15.03	$15.04	$14.12	$14.17	$15.57	$14.95	$13.93
1.5% SULFUR	$13.99	$13.74	$13.13	$14.64	$14.47	$14.40	$14.36	$13.61	$13.74	$15.05	$14.43	$13.15
2.0% SULFUR	$13.34	$13.20	$12.49	$14.09	$13.92	$13.77	$13.68	$13.09	$13.30	$14.53	$13.91	$12.51
2.2% SULFUR	$13.13	$13.04	$12.29	$13.92	$13.75	$13.56	$13.46	$12.93	$13.18	$14.37	$13.75	$12.31
3.0% SULFUR	$12.32	$12.41	$11.50	$13.27	$13.11	$12.78	$12.61	$12.33	$12.72	$13.78	$13.15	$11.50

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

BASE CASE

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$22.40	$21.74	$20.80	$21.47	$21.23	$20.16	$20.04	$20.40	$21.70	$22.43	$21.48	$20.58
0.5% SULFUR	$21.04	$20.38	$19.43	$20.10	$19.87	$18.78	$18.67	$19.02	$20.32	$21.05	$20.10	$19.20

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COST

SOLID FUELS ($/MMBTU)

JANUARY THROUGH DECEMBER, 2000

BASE CASE

	2000											
FUEL TYPE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
SOLID FUEL	$1.32	$1.32	$1.32	$1.33	$1.33	$1.33	$1.33	$1.33	$1.34	$1.34	$1.34	$1.34

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2000

BASE CASE

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	JANUARY	FEBRUARY		APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	455	455	#	480	630	630	630	650	650	500	465	465
NON-FIRM	225	225	#	225	70	70	70	70	70	215	215	215
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$2.85	$2.31		$2.21	$2.26	$2.21	$2.30	$2.09	$2.00	$2.25	$2.47	$2.65
NON-FIRM	$3.15	$2.62		$2.51	$2.56	$2.52	$2.61	$2.40	$2.31	$2.56	$2.78	$2.97

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

LOW

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$12.44	$11.87	$11.32	$12.52	$12.64	$12.38	$12.20	$11.66	$11.82	$13.07	$12.53	$11.54
1.0% SULFUR	$11.28	$10.83	$10.30	$11.49	$11.41	$11.28	$11.16	$10.61	$10.72	$11.93	$11.36	$10.40
1.5% SULFUR	$10.63	$10.28	$9.70	$10.94	$10.85	$10.67	$10.53	$10.09	$10.25	$11.36	$10.82	$9.66
2.0% SULFUR	$9.98	$9.73	$9.09	$10.38	$10.29	$10.08	$9.90	$9.56	$9.77	$10.83	$10.27	$9.08
2.2% SULFUR	$9.77	$9.56	$8.90	$10.21	$10.12	$9.86	$9.70	$9.40	$9.64	$10.66	$10.11	$8.88
3.0% SULFUR	$8.96	$8.92	$8.18	$9.54	$9.45	$9.12	$8.92	$8.79	$9.11	$10.01	$9.47	$8.14

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

LOW

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$17.62	$16.88	$15.98	$16.67	$16.56	$15.58	$15.36	$15.76	$16.80	$17.59	$16.74	$15.80
0.5% SULFUR	$16.26	$15.52	$14.61	$15.31	$15.19	$14.21	$13.98	$14.38	$15.42	$16.21	$15.36	$14.41

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2000

LOW

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	2000 JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	455	455	455	480	630	630	630	650	650	500	465	465
NON-FIRM	225	225	225	225	70	70	70	70	70	215	215	215
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$2.33	$1.80	$1.68	$1.69	$1.74	$1.70	$1.79	$1.57	$1.49	$1.74	$1.95	$2.14
NON-FIRM	$2.64	$2.10	$1.99	$2.00	$2.05	$2.00	$2.09	$1.88	$1.79	$2.05	$2.26	$2.45

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

HIGH

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.7% SULFUR	$17.58	$17.13	$16.63	$16.15	$16.24	$16.16	$16.16	$17.05	$17.13	$16.64	$16.07	$17.03
1.0% SULFUR	$16.44	$16.12	$15.62	$17.17	$16.95	$17.05	$17.13	$16.01	$16.03	$17.52	$16.69	$15.83
1.5% SULFUR	$15.79	$15.60	$14.97	$16.63	$16.42	$16.41	$16.43	$15.50	$15.62	$17.02	$16.38	$15.03
2.0% SULFUR	$15.14	$15.07	$14.32	$16.08	$15.88	$15.76	$15.72	$14.99	$15.20	$16.52	$15.86	$14.36
2.2% SULFUR	$14.93	$14.91	$14.11	$15.92	$15.71	$15.56	$15.49	$14.83	$15.09	$16.37	$15.71	$14.16
3.0% SULFUR	$14.12	$14.29	$13.31	$15.28	$15.08	$14.76	$14.60	$14.24	$14.65	$15.60	$15.12	$13.31

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL ($/BBL)

JANUARY THROUGH DECEMBER, 2000

HIGH

	2000											
SULFUR GRADE	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
0.3% SULFUR	$24.97	$24.36	$23.39	$24.05	$23.75	$22.61	$22.56	$22.89	$24.33	$25.03	$24.03	$23.16
0.5% SULFUR	$23.61	$23.00	$22.02	$22.68	$22.38	$21.24	$21.19	$21.52	$22.95	$23.65	$22.64	$21.77

FLORIDA POWER & LIGHT COMPANY

PROJECTED TOTAL NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

JANUARY THROUGH DECEMBER, 2000

HIGH

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
FIRM TRANSPORTATION	455	455	455	480	630	630	630	650	650	500	465	465
NON-FIRM	225	225	225	225	70	70	70	70	70	215	215	215
WEIGHTED-AVERAGE DISPATCH PRICE BY TYPE OF TRANSPORTATION SERVICE ($/MMBTU)												
FIRM TRANSPORTATION	$3.18	$2.64	$2.53	$2.54	$2.59	$2.55	$2.64	$2.42	$2.34	$2.59	$2.80	$2.99
NON-FIRM	$3.49	$2.95	$2.84	$2.85	$2.90	$2.85	$2.94	$2.73	$2.64	$2.90	$3.11	$3.30

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
Period Of: January, 2000 through December, 2000

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)		OVERHAUL DATES		OVERHAUL DATES
Cape Canaveral 1	2.0	3.6	0.0		NONE		
Cape Canaveral 2	1.0	2.7	15.3		02/26/00-04/21/00		
Cutler 5	1.3	0.9	0.0		NONE		
Cutler 6	1.3	1.3	0.0		NONE		
Fort Myers 1	0.9	3.3	0.0		NONE		
Fort Myers 2	2.0	4.0	0.0		NONE		
Lauderdale 4	0.9	4.4	2.7		04/01/00-04/10/00		
Lauderdale 5	0.9	4.4	2.7		10/02/00-10/11/00		
Manatee 1	2.4	3.4	0.0		11/10/00-12/14/00		
Manatee 2	0.9	2.9	13.4		02/19/00-03/22/00		
Martin 1	1.5	3.2	0.0		NONE		
Martin 2	1.5	2.7	0.0		03/13/00-04/11/00		
Martin 3	1.1	4.6	1.6	**	02/24/00-03/15/00	**	10/17/00-10/22/00
Martin 4	1.0	4.5	2.9	**	09/23/00-10/02/00		
Port Everglades 1	1.0	2.2	3.8		02/15/00-02/26/00		
Port Everglades 2	1.3	2.3	3.8		10/12/00-10/23/00		
Port Everglades 3	0.7	3.4	0.0		NONE		
Port Everglades 4	0.8	3.0	7.7		11/24/00-12/21/00		
Putnam 1	1.0	3.4	4.8	**	11/11/00-11/22/00		
Putnam 2	1.1	3.3	7.8	**	02/23/00-03/05/00		
Riviera 3	2.2	3.1	16.4		03/03/00-05/05/00		
Riviera 4	3.7	3.9	0.0		NONE		
Sanford 3	0.7	1.9	0.0		10/07/00-10/20/00		
Sanford 4	2.0	3.5	0.0		NONE		
Sanford 5	2.1	3.4	0.0		NONE		
Turkey Point 1	2.0	3.5	7.7		03/04/00-03/31/00		
Turkey Point 2	4.1	3.8	0.0		NONE		
Turkey Point 3	2.3	2.3	9.6		02/28/00-04/03/00		
Turkey Point 4	2.3	2.3	9.6		10/02/00-11/06/00		
St.Lucie 1	2.5	2.5	0.0		NONE		
St.Lucie 2	2.3	2.3	9.6		04/17/00-05/22/00		
SJRPP 1	2.1	4.6	0.0		NONE		
SJRPP 2	2.1	4.2	8.2		03/11/00-04/10/00		
Scherer 4	2.0	4.6	0.0		NONE		

** Note: Partial Planned Outage.

Based on outage hours submitted for IRP
FOF=FOH/8784 ; POF=POH/8784; POF=POH/8784

2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 990001-EI

APRIL 1, 1999

GENERATING PERFORMANCE INCENTIVE FACTOR

PERFORMANCE RESULTS AND GPIF CALCULATION FOR

OCTOBER, 1997 THROUGH SEPTEMBER, 1998

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 2
COMPANY/ WITNESS: Silva
DATE 11-22-99

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 990001-EI

APRIL 1, 1999

Q. Please state your name and business address.

A. My name is Rene Silva and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Mr. Silva, would you please state your present position with Florida Power and Light Company (FPL).

A. I am Manager of Forecasting and Regulatory Response, in the Power Generation Business Unit of FPL.

Q. Mr. Silva, have you previously presented testimony in this docket?

A. Yes, I have.

Q. Mr. Silva, what is the purpose of your testimony?

A. The purpose of my testimony is to report the actual performance for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the sixteen (16) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-97-1045-FOF-EI issued September 5, 1997, for

the period October, 1997, through September, 1998, and have performed the calculations prescribed by the GPIF Rule based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

Q. Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?

A. Yes, I have. It consists of one document. Page 1 of that document is an index to the contents of the document.

Q. What is the incentive amount you have calculated for the period OCTOBER, 1997 THROUGH SEPTEMBER, 1998?

A. I have calculated a GPIF incentive reward of $ 9,669,694.

Q. Please explain how the reward amount is calculated?

A. The steps involved in making this calculation are provided in Document No. 1. Page 2 of Document No. 1 provides the GPIF Reward/Penalty Table (Actual) which shows an overall GPIF performance point value of +4.98 corresponding to a GPIF reward of $9,669,694. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each unit, the unit's performance indicators (ANOHR and EAF), the weighting factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the sixteen (16) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6, and Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to, and approved by, the Commission prior to the start of the period. These tables are shown on pages 8 through 23.

Page 7 shows the adjustments to ANOHR. For each of the sixteen (16) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission prior to the beginning of the period. These tables are also shown on pages 8 through 23.

Q. Are there any changes to the targets approved through Commission Order No. PSC-97-1045-FOF-EI?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the October, 1997 through September, 1998 period?

A. The primary reason that FPL will receive a reward for the period was that Turkey Point Nuclear Units 3 and 4 and St. Lucie Nuclear Units 1 and 2 achieved better availability than was targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward?

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 98.0%, compared to its target of 92.8%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $2,259,281.

Turkey Point Unit 4 operated at an adjusted actual EAF of 94.8%, compared to its target of 89.1%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $2,098,730.

St. Lucie Unit 1 operated at an adjusted actual EAF of 77.5%, compared to its target of 72.7%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $2,041,674.

St. Lucie Unit 2 operated at an adjusted actual EAF of 99.4%, compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $2,256,943.

The total GPIF reward due to the nuclear units' actual availability performance is $8,656,628.

Q. Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 11,026 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,016 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,792 BTU/KWH, which was better than projected by 121 BTU/KWH. This will result in a +9.97 point reward, which corresponds to a GPIF reward of $297,198.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,826 BTU/KWH, which was better than projected by 114 BTU/KWH. This will result in a +4.15 point reward, which corresponds to a GPIF reward of $226,323.

In total, the nuclear units' heat rate performance results in a GPIF reward of $523,521.

Q. What is the total GPIF incentive reward for FPL's nuclear units?

A. $9,180,149.

Q. Mr. Silva, would you summarize the performance of FPL's fossil units?

A. Yes eleven (11) of the twelve (12) generating units performed better than their availability targets, while the remaining unit performed worse than its target. The combined fossil unit availability performance results in a GPIF reward of $1,056,714.

Two (2) of the units operated with ANOHR's that were better than their projected targets and four (4) units operated with ANOHR's that were worse than their projected targets. The remaining six (6) units operated with ANOHR's that were within the +/- 75 BTU/KWH deadband around the projected targets and they will receive no incentive reward or penalty. In total, the combined fossil units heat rate performance results in a GPIF penalty of $567,169.

In total, the GPIF reward for FPL's fossil units for the period of October, 1997 through September, 1998 is $489,545.

Q. Does this conclude your testimony?

A. Yes, it does.

3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 990001-EI

APRIL 1, 1999

GENERATING PERFORMANCE INCENTIVE FACTOR

PERFORMANCE RESULTS AND GPIF CALCULATION FOR

OCTOBER, 1998 THROUGH DECEMBER, 1998

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 3
COMPANY/ WITNESS: Silva
DATE: 11-22-99

BEFORE THE PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF R. SILVA

DOCKET NO. 990001-EI

APRIL 1, 1999

Q. Please state your name and business address.

A. My name is Rene Silva and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Mr. Silva, would you please state your present position with Florida Power and Light Company (FPL).

A. I am Manager of Forecasting and Regulatory Response, in the Power Generation Business Unit of FPL.

Q. Mr. Silva, have you previously presented testimony in this docket?

A. Yes, I have.

Q. Mr. Silva, what is the purpose of your testimony?

A. The purpose of my testimony is to report the actual performance for the Equivalent Availability Factor (EAF) and Average Net Operating Heat Rate (ANOHR) for the sixteen (16) generating units used to determine the Generating Performance Incentive Factor (GPIF). I have compared the actual performance of each unit to the targets that were approved in Commission Order No. PSC-98-1715-FOF-EI issued December 18, 1998,

for the period October, 1998, through December, 1998, and have performed the calculations prescribed by the GPIF Rule based on this comparison. My testimony presents the result of my calculations, which is an incentive reward for the period.

Q. Have you prepared, or caused to have prepared under your direction, supervision or control, an exhibit in this proceeding?

A. Yes, I have. It consists of one document. Page 1 of that document is an index to the contents of the document.

Q. What is the incentive amount you have calculated for the period OCTOBER, 1998 THROUGH DECEMBER, 1998?

A. I have calculated a GPIF incentive reward of $ 1,697,372.

Q. Please explain how the reward amount is calculated?

A. The steps involved in making this calculation are provided in Document No. 1. Page 2 of Document No. 1 provides the GPIF Reward/Penalty Table (Actual) which shows an overall GPIF performance point value of +3.45 corresponding to a GPIF reward of $1,697,372. Page 3 provides the calculation of the maximum allowed incentive dollars. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each unit, the unit's performance indicators (ANOHR and EAF), the weighting factors and the associated GPIF points.

Page 5 is the actual EAF and adjustments summary. This page lists each of the sixteen (16) units, the actual outage factors and the actual EAF, in columns 1 through 5. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6, and Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined from the tables submitted to, and approved by, the Commission prior to the start of the period. These tables are shown on pages 8 through 23.

Page 7 shows the adjustments to ANOHR. For each of the sixteen (16) units, it shows the target heat rate formula, the actual Net Output Factor (NOF) and the actual ANOHR in columns 1 through 4. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment is to provide a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance Incentive Points that have been determined from the table submitted for each unit and approved by the Commission prior to the beginning of the period. These tables are also shown on pages 8 through 23.

Q. Are there any changes to the targets approved through Commission Order No. PSC-98-1715-FOF-EI ?

A. No, the approved targets have not changed.

Q. Please explain the primary reason or reasons why FPL will be rewarded under the GPIF for the October, 1998 through December, 1998 period?

A. The primary reason that FPL will receive a reward for the period was that Turkey Point Nuclear Units 3 and 4 and St. Lucie Nuclear Units 1 and 2 achieved better availability than was targeted.

Q. Please summarize the effect of FPL's nuclear unit availability on the GPIF reward?

A. Turkey Point Unit 3 operated at an adjusted actual EAF of 68.5%, compared to its target of 67.1%. This results in a +4.65 point reward, which corresponds to a GPIF reward of $169,199.

Turkey Point Unit 4 operated at an adjusted actual EAF of 100.0%, compared to its target of 93.6%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $534,301.

St. Lucie Unit 1 operated at an adjusted actual EAF of 99.6%, compared to its target of 92.8%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $621,522.

St. Lucie Unit 2 operated at an adjusted actual EAF of 60.6%, compared to its target of 57.1%. This results in a +10.00 point reward, which corresponds to a GPIF reward of $326,766.

The total GPIF reward due to the nuclear units' actual availability performance is $1,651,788.

Q. Please summarize each nuclear unit's performance as it relates to the ANOHR of the units.

A. Turkey Point Unit 3 operated with an adjusted actual ANOHR of 10,890 BTU/KWH, which was better than projected by 140 BTU/KWH. This will result in a +3.41 point reward, which corresponds to a GPIF reward of $79,177.

Turkey Point Unit 4 operated with an adjusted actual ANOHR of 11,023 BTU/KWH, which was better than projected by 114 BTU/KWH. This will result in a +2.14 point reward, which corresponds to a GPIF reward of $68,306.

St. Lucie Unit 1 operated with an adjusted actual ANOHR of 10,790 BTU/KWH, which was better than projected by 81 BTU/KWH. This will result in a +0.60 point reward, which corresponds to a GPIF reward of $9,264.

St. Lucie Unit 2 operated with an adjusted actual ANOHR of 10,804 BTU/KWH. This ANOHR is within the ± 75 BTU/KWH deadband around the projected target, therefore there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a GPIF reward of $156,747.

Q. What is the total GPIF incentive reward for FPL's nuclear units?

A. $1,808,535.

Q. Mr. Silva, would you summarize the performance of FPL's fossil units?

A. Yes, five (5) of the twelve (12) generating units performed better than their availability targets, while the remaining units performed worse than its target. The combined fossil unit availability performance results in a GPIF reward of $15,415.

Two (2) of the units operated with ANOHR's that were better than their projected targets and five (5) units operated with ANOHR's that were worse than their projected targets. The remaining five (5) units operated with ANOHR's that were within the +/- 75 BTU/KWH deadband around the projected targets and they will receive no incentive reward or penalty. In total, the combined fossil unit heat rate performance results in a GPIF penalty of $126,577.

In total, the GPIF penalty for FPL's fossil units for the period of October, 1998 through December, 1998 is $111,162.

Q. Does this conclude your testimony?

A. Yes, it does.

4

DOCUMENT NO. 1

WITNESS: R. SILVA

DOCKET NO. 990001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY, 2000 THROUGH DECEMBER, 2000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 4
COMPANY/ WITNESS: Silva
DATE 11-22-99

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY, 2000 THROUGH DECEMBER, 2000

DOCUMENT	INDEX OF MANUAL PAGES	TITLE
1	7.201.001	Index of Manual Pages
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 to 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 to 7.201.028	Unit MOF and FOF Versus Time Graphs
	7.201.029	Planned Outages Schedules (Estimated)

Table 2.0
POWRSYM Projected System Generation
Period Of: January 2000 Through December 2000

Name	Unit	Capacity* (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
St. Lucie	1	845	8344	7049000	100.0%	9.45	9.45	23220
St Lucie	2	719	7546	5429000	100.1%	7.28	16.74	18180
Turkey Point	4	703	7546	5310000	100.1%	7.12	23.86	14890
Turkey Point	3	703	7546	5295000	99.8%	7.10	30.96	15650
Scherer	4	625	8252	5021000	97.4%	6.73	37.69	84960
Martin	3	476	8271	3853000	97.9%	5.17	42.86	74140
Martin	4	476	8283	3820000	96.9%	5.12	47.98	72690
Ft. lauderdale	4	439	8060	3476000	98.2%	4.66	52.65	71700
Ft. Lauderdale	5	439	8052	3466000	98.1%	4.65	57.29	71690
Ft. Myers	2	398	8183	2989000	91.8%	4.01	61.30	65970
Cape Canaveral	1	389	7397	2201000	76.5%	2.95	64.26	54320
Port Everglades	3	404	6758	2134000	78.2%	2.86	67.12	54360
Manatee	2	795	3632	2000000	69.3%	2.68	69.80	54120
Sanford	4	384	6387	1883000	76.8%	2.53	72.33	48070
Port Everglades	4	402	5599	1764000	78.4%	2.37	74.69	44800
Cape Canaveral	2	402	5384	1647000	76.1%	2.21	76.90	41260
Sanford	5	384	5345	1548000	75.4%	2.08	78.98	40090
Putnam	1	247	7488	1694000	91.6%	2.27	81.25	36310
Riviera	4	281	6500	1427000	78.1%	1.91	83.16	34600
Martin	2	820	3191	1764000	67.4%	2.37	85.53	47060
Manatee	1	799	2354	1141000	60.7%	1.53	87.06	31280
Putnam	2	247	7058	1518000	87.1%	2.04	89.09	32980
Turkey Point	1	402	3993	1212000	75.5%	1.63	90.72	31230
Riviera	3	281	4935	1050000	75.7%	1.41	92.13	25750
Turkey Point	2	401	4079	1163000	71.1%	1.56	93.69	29910
St. Johns River	1	119	8784	1043000	99.8%	1.40	95.09	11770
St. Johns River	2	118	8064	953000	100.2%	1.28	96.37	10640
Martin	1	817	1549	828000	65.4%	1.11	97.48	22250
Ft. Myers	1	141	6397	767000	85.0%	1.03	98.50	18580
Port Everglades	2	211	2298	359000	74.0%	0.48	98.99	9870
Sanford	3	144	1632	188000	80.0%	0.25	99.24	5160
Ft. Myers GT	(1-12)	672	397	218000	81.7%	0.29	99.53	11180
Port Everglades	1	211	861	142000	78.2%	0.19	99.72	3970
Ft. lauderdale GT	(1-24)	864	174	105000	69.8%	0.14	99.86	4560
Cutler	6	144	680	57000	58.2%	0.08	99.94	1830
Port Everglades GT	(1-12)	432	82	25000	70.6%	0.03	99.97	1170
Cutler	5	71	593	21000	49.9%	0.03	100.00	750
Totals				74560000		100.00	100.00	1220960

* Weighted average 5 months winter 7 months summer.

TABLE 3.0

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

PERIOD OF: January, 2000 through december, 2000

Cape Canaveral Unit No. 1
Cape Canaveral Unit No. 2

Ft. Lauderdale Unit No. 4
Ft. Lauderdale Unit No. 5

Ft. Myers Unit No. 2

Martin Unit No. 3
Martin Unit No. 4

Manatee Unit No. 2

Port Everglades Unit No. 3
Port Everglades Unit No. 4

Putnam Unit No. 1

Sanford Unit No. 4
Sanford Unit No. 5

Turket Point Unit No. 3
Turket Point Unit No. 4

St. Lucie Unit No. 1
St. Lucie Unit No. 2

Scherer Unit No. 4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

Generating Performance Incentive Points (GPIE)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	39,554.00	19,777.71
+ 9	35,598.60	17,799.94
+ 8	31,643.20	15,822.17
+ 7	27,687.80	13,844.40
+ 6	23,732.40	11,866.63
+ 5	19,777.00	9,888.86
+ 4	15,821.60	7,911.09
+ 3	11,866.20	5,933.31
+ 2	7,910.80	3,955.54
+ 1	3,955.40	1,977.77
0	0.00	0.00
- 1	(4,077.00)	(1,977.77)
- 2	(8,154.00)	(3,955.54)
- 3	(12,231.00)	(5,933.31)
- 4	(16,308.00)	(7,911.09)
- 5	(20,385.00)	(9,888.86)
- 6	(24,462.00)	(11,866.63)
- 7	(28,539.00)	(13,844.40)
- 8	(32,616.00)	(15,822.17)
- 9	(36,693.00)	(17,799.94)
- 10	(40,770.00)	(19,777.71)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY		$	4,808,619,000
	END OF MONTH BALANCE OF COMMON EQUITY			
LINE 2	MONTH OF JANUARY	2000	$	4,830,894,000
LINE 3	MONTH OF FEBRUARY	2000	$	4,827,730,000
LINE 4	MONTH OF MARCH	2000	$	4,815,886,000
LINE 5	MONTH OF APRIL	2000	$	4,829,386,000
LINE 6	MONTH OF MAY	2000	$	4,848,134,000
LINE 7	MONTH OF JUNE	2000	$	4,862,293,000
LINE 8	MONTH OF JULY	2000	$	4,874,557,000
LINE 9	MONTH OF AUGUST	2000	$	4,884,516,000
LINE 10	MONTH OF SEPTEMBER	2000	$	4,870,206,000
LINE 11	MONTH OF OCTOBER	2000	$	4,847,938,000
LINE 12	MONTH OF NOVEMBER	2000	$	4,828,548,000
LINE 13	MONTH OF DECEMBER	2000	$	4,813,512,000
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD		$	4,841,709,000
	(SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)			
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS		$	20,020,497
	(LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)			
LINE 18	JURISDICTIONAL SALES			85,722,254,662 KWH
LINE 19	TOTAL SALES			86,774,547,883 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR			98.79%
	(LINE 18 DIVIDED BY LINE 19)			
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	19,777,714

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 1	0.12	92.4	94.9	89.9	48.42	-48.78
Cape Canaveral 2	0.15	78.2	80.7	75.7	59.76	-45.35
Lauderdale 4	0.68	93.5	95.5	91.5	269.54	-269.09
Lauderdale 5	0.66	93.5	95.5	91.5	260.62	-260.09
Fort Myers 2	0.39	92.7	95.2	90.2	154.4	-153.33
Manatee 2	0.35	71.7	75.7	67.7	138.93	-138.73
Martin 3	0.92	94.2	96.2	92.2	363.06	-362.68
Martin 4	1.18	91.6	94.1	89.1	467.01	-467.23
Port Everglades 3	0.13	95.8	97.8	93.8	52.56	-52.86
Port Everglades 4	0.11	88.2	90.2	86.2	43.09	-43.18
Putnam 1	0.29	91.2	93.2	89.2	115.72	-115.96
Sanford 4	0.15	92.3	94.8	89.8	57.88	-58.09
Sanford 5	0.21	89.3	92.8	85.8	82.82	-83.03
Turkey Point 3	8.89	84.6	87.6	81.6	3516.26	-3513.08
Turkey Point 4	8.86	84.6	87.6	81.6	3502.79	-3500.23
St.Lucie 1	11.62	93.6	96.6	90.6	4597.41	-4589.02
St.Lucie 2	8.84	84.6	87.6	81.6	3497.1	-3494.26
Scherer 4	2.55	94.2	96.7	91.7	1010.21	-1460.32
	46.11				18237.58	-18655.31

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOE	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 1	1.29	9511	76.5	9347	9676	509.0	509.0
Cape Canaveral 2	0.90	9690	76.1	9531	9848	356.4	356.4
Lauderdale 4	1.14	7349	98.2	7228	7471	450.6	450.6
Lauderdale 5	1.12	7358	98.1	7237	7479	444.2	444.2
Fort Myers 2	2.20	9321	91.8	9123	9519	869.6	869.6
Manatee 2	4.82	10162	69.3	9729	10595	1905.6	1905.6
Martin 3	6.00	6996	97.9	6697	7295	2372.1	2372.1
Martin 4	5.38	6906	96.9	6629	7183	2127.0	2127.0
Port Everglades 3	3.40	9748	78.2	9432	10064	1344.9	1344.9
Port Everglades 4	2.80	9864	78.4	9350	9978	1107.5	1107.5
Putnam 1	0.75	8937	91.6	8789	9085	296.9	296.9
Sanford 4	3.93	10016	76.8	9617	10415	1555.4	1555.4
Sanford 5	3.27	10290	75.4	9883	10696	1292.8	1292.8
Turkey Point 3	4.84	11086	99.8	10834	11297	1914.8	1839.1
Turkey Point 4	5.56	11093	100.1	10837	11349	2197.7	2830.5
St.Lucie 1	2.94	10854	100.0	10699	11009	1163.2	1205.5
St.Lucie 2	1.93	10872	100.1	10743	11001	763.6	1163.2
Scherer 4	1.63	9989	97.4	9838	10141	647.5	647.5
	53.89					21318.9	22117.9

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

				ANOHR Equation						
Plant/Unit	ANOHR	MOE	MSC	a	b	Bounds	R-sqr	First	Last	Exclusions
Cape Canaveral 1	9511	76.5	389	10099.0	-7.68	164.1	0.26	06-96	05-99	04-96
Cape Canaveral 2	9690	76.1	402	9971.7	-3.71	158.7	0.11	06-96	05-99	06-97, 11-97
Lauderdale 4	7349	98.2	439	8135.4	-8.00	121.2	0.52	06-96	05-99	
Lauderdale 5	7358	98.1	439	8205.2	-8.64	120.6	0.46	06-96	05-99	
Fort Myers 2	9321	91.8	398	10086.3	-8.34	197.9	0.35	06-96	05-99	
Manatee 2	10162	69.3	795	11026.0	-12.47	432.8	0.17	06-96	05-99	
Martin 3	6996	97.9	476	7156.0	-1.63	298.8	0.00	06-96	05-99	12-96
Martin 4	6906	96.9	476	7356.6	-4.65	277.1	0.12	06-96	05-99	06-96-10-96
Port Everglades 3	9748	78.2	404	11474.5	-22.09	316.2	0.57	06-96	05-99	02-97,04-99,04-99
Port Everglades 4	9664	78.4	402	11576.4	-24.40	313.9	0.67	06-96	05-99	12-97,01-98,04-98,05-98
Putnam 1	8937	91.6	247	9657.6	-7.86	148.1	0.65	06-96	05-99	
Sanford 4	10016	76.8	384	10078.5	-0.81	399.1	0.00	06-96	05-99	11-96,6-98-9-98,11-98,12-98
Sanford 5	10290	75.4	384	10513.9	-2.97	406.8	0.01	06-96	05-99	11-96-2-97,12-97-02-98
Turkey Point 3	11066	99.8	703	14496.4	-34.37	231.5	0.50	06-96	05-99	03-97,10-98
Turkey Point 4	11093	100.1	703	14660.9	-35.64	256.3	0.43	06-96	05-99	09-97
St.Lucie 1	10854	100.0	845	12915.6	-20.62	155.3	0.55	06-96	05-99	06-96,07-96, 11-97,12-97
St.Lucie 2	10872	100.1	719	12382.3	-15.09	128.8	0.39	06-96	05-99	11/96
Scherer 4	9989	97.4	625	11350.7	-13.98	151.1	0.23	06-96	05-99	10-96,04-98,07-98

DERRIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

PRODUCTION COSTING SIMULATION
FUEL COST ($000'S)

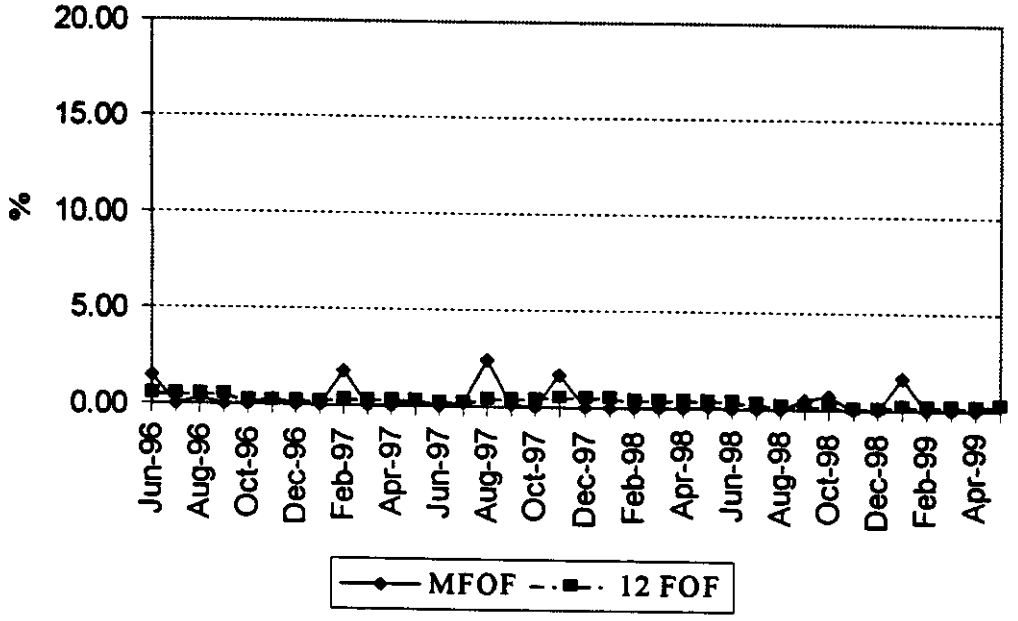
Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Cape Canaveral 1	EAF	1220960	1221008	48.4	0.12
	ANHR	1220960	1221469	509.0	1.29
Cape Canaveral 2	EAF	1220960	1221020	59.8	0.15
	ANHR	1220960	1221316	356.4	0.90
Lauderdale 4	EAF	1220960	1221230	269.5	0.68
	ANHR	1220960	1221411	450.6	1.14
Lauderdale 5	EAF	1220960	1221221	260.6	0.66
	ANHR	1220960	1221404	444.2	1.12
Fort Myers 2	EAF	1220960	1221114	154.4	0.39
	ANHR	1220960	1221830	869.6	2.20
Manatee 2	EAF	1220960	1221099	138.9	0.35
	ANHR	1220960	1222866	1905.6	4.82
Martin 3	EAF	1220960	1221323	363.1	0.92
	ANHR	1220960	1223332	2372.1	6.00
Martin 4	EAF	1220960	1221427	467.0	1.18
	ANHR	1220960	1223087	2127.0	5.38
Port Everglades 3	EAF	1220960	1221013	52.6	0.13
	ANHR	1220960	1222305	1344.9	3.40
Port Everglades 4	EAF	1220960	1221003	43.1	0.11
	ANHR	1220960	1222068	1107.5	2.80
Putnam 1	EAF	1220960	1221076	115.7	0.29
	ANHR	1220960	1221257	296.9	0.75
Sanford 4	EAF	1220960	1221018	57.9	0.15
	ANHR	1220960	1222515	1555.4	3.93
Sanford 5	EAF	1220960	1221043	82.8	0.21
	ANHR	1220960	1222253	1292.8	3.27
Turkey Point 3	EAF	1220960	1224476	3516.3	8.89
	ANHR	1220960	1222875	1914.8	4.84
Turkey Point 4	EAF	1220960	1224463	3502.8	8.86
	ANHR	1220960	1223158	2197.7	5.56
St.Lucie 1	EAF	1220960	1225557	4597.4	11.62
	ANHR	1220960	1222123	1163.2	2.94
St.Lucie 2	EAF	1220960	1224457	3497.1	8.84
	ANHR	1220960	1221724	763.6	1.93
Scherer 4	EAF	1220960	1221970	1010.2	2.55
	ANHR	1220960	1221607	647.5	1.64
	TOTAL			39556.5	100.00

(1) FUEL ADJUSTMENT HIGH BAND CASE - ALL UNIT PERFORMANCE INDICATORS AT TARGET
(2) ALL OTHER UNIT PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

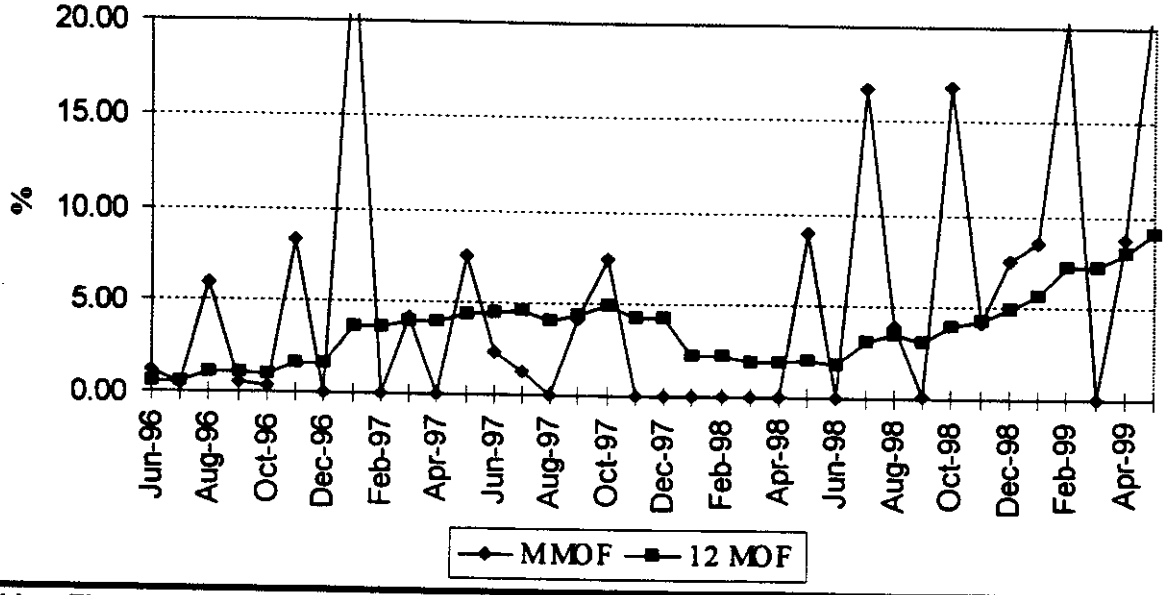
ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

Plant/Unit	EAF	EPOF	EUOF	EUOR	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET_GEN
Cape Canaveral 1	92.4	0.0	7.6	8.3	8760	7397	697.2	665.8	0.0	175.2	490.6	2201000
Cape Canaveral 2	78.2	15.8	6.0	8.9	8760	5384	1466.3	1909.7	1384.1	148.9	376.7	1647000
Lauderdale 4	93.5	2.7	3.8	4.0	8760	8060	130.6	569.4	236.5	166.4	166.4	3476000
Lauderdale 5	93.5	2.7	3.8	4.0	8760	8052	138.6	569.4	236.5	166.4	166.4	3466000
Fort Myers 2	92.7	0.0	7.3	7.3	8760	8121	0.0	639.5	0.0	175.2	464.3	2989000
Manatee 2	71.7	13.9	14.4	25.8	8760	3632	2648.9	2479.1	1217.6	770.9	490.6	2000000
Martin 3	94.2	1.8	4.0	4.1	8760	8252	0.0	508.1	157.7	175.2	175.2	3853000
Martin 4	91.6	2.9	5.5	5.7	8760	8024	0.0	735.8	254.0	315.4	166.4	3820000
Port Everglades 3	95.8	0.0	4.2	5.2	8760	6758	1634.1	367.9	0.0	175.2	192.7	2134000
Port Everglades 4	88.2	8.2	3.6	5.3	8760	5599	2127.3	1033.7	718.3	157.7	157.7	1764000
Putnam 1	91.2	4.9	3.8	4.3	8760	7488	509.9	762.1	429.2	166.4	166.4	1694000
Sanford 4	92.3	0.0	7.7	9.6	8760	6387	1698.5	674.5	0.0	175.2	499.3	1883000
Sanford 5	89.3	0.0	10.7	14.9	8760	5345	2477.7	937.3	0.0	385.4	551.9	1548000
Turkey Point 3	84.6	9.6	5.8	6.4	8760	7411	0.0	1349.0	841.0	254.0	254.0	5295000
Turkey Point 4	84.6	9.6	5.8	6.4	8760	7411	0.0	1349.0	841.0	254.0	254.0	5310000
St.Lucie 1	93.6	0.0	6.4	6.4	8760	8199	0.0	560.6	0.0	280.3	280.3	7049000
St.Lucie 2	84.6	9.6	5.8	6.4	8760	7411	0.0	1349.0	841.0	254.0	254.0	5429000
Scherer 4	94.2	0.0	5.8	5.8	8760	8252	0.0	508.1	0.0	332.9	175.2	5021000

PCC 1
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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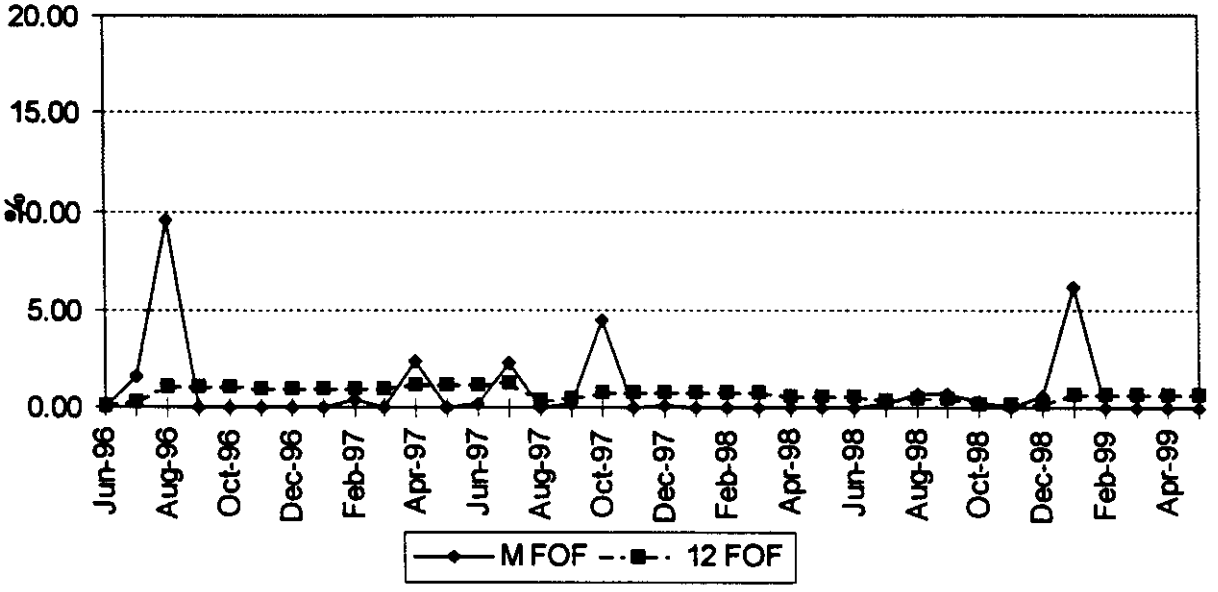
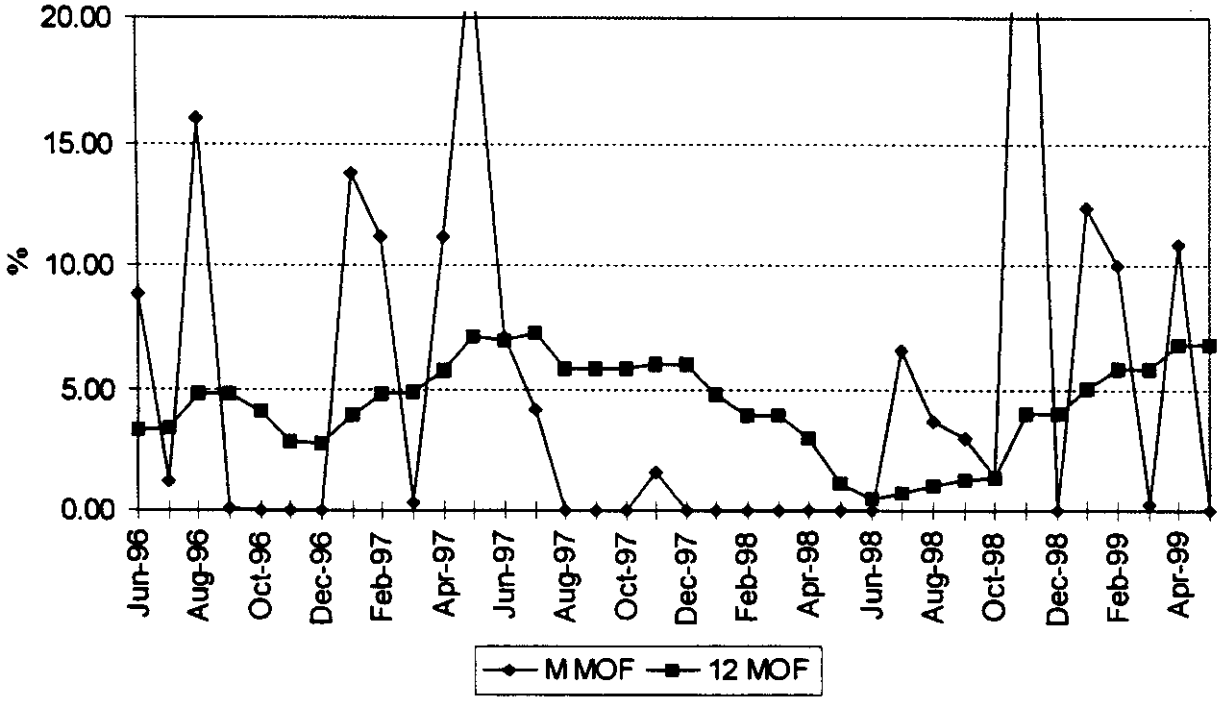


MAINTENANCE OUTAGE FACTOR



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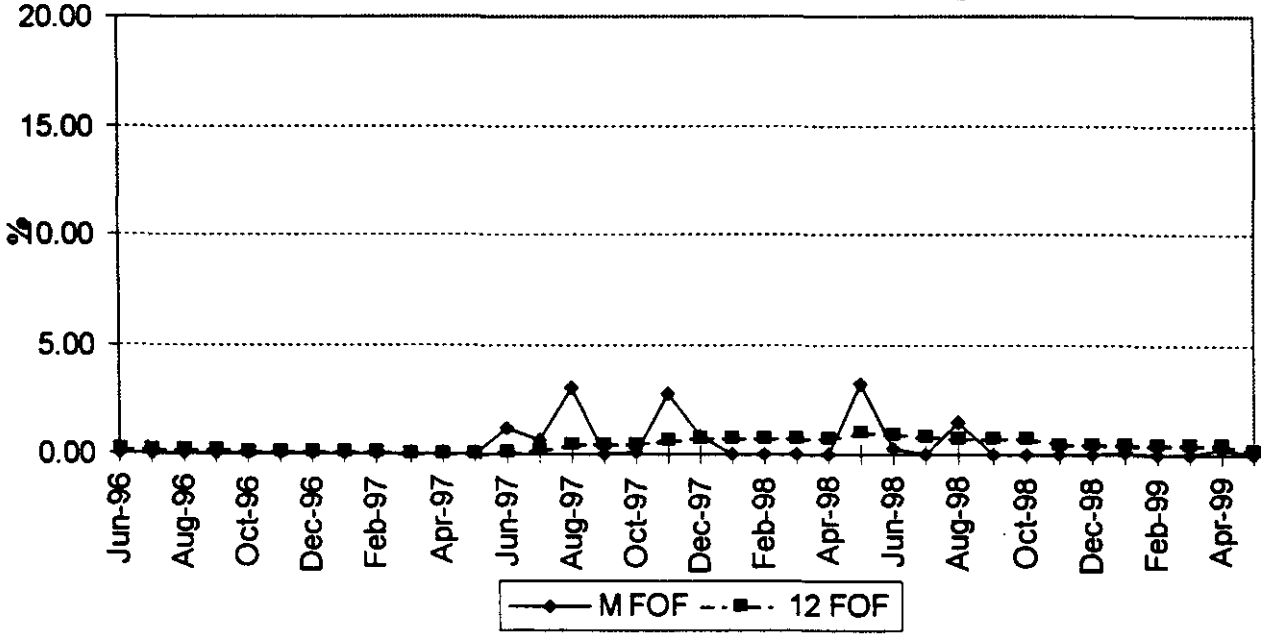
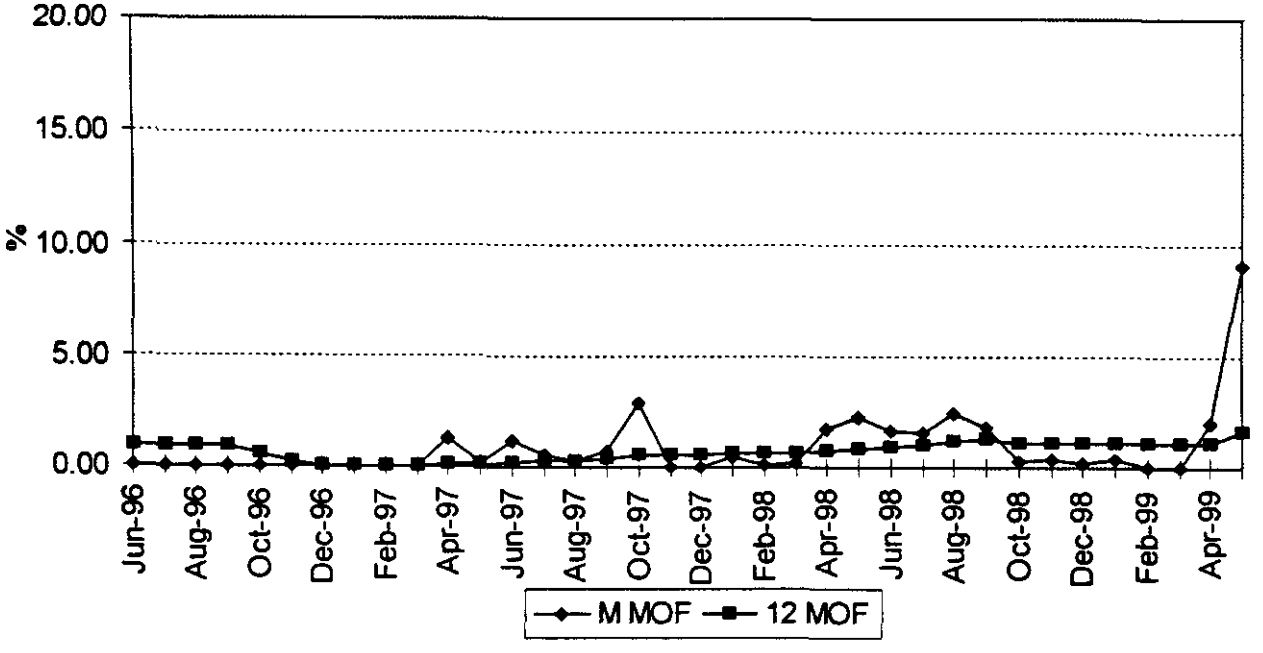
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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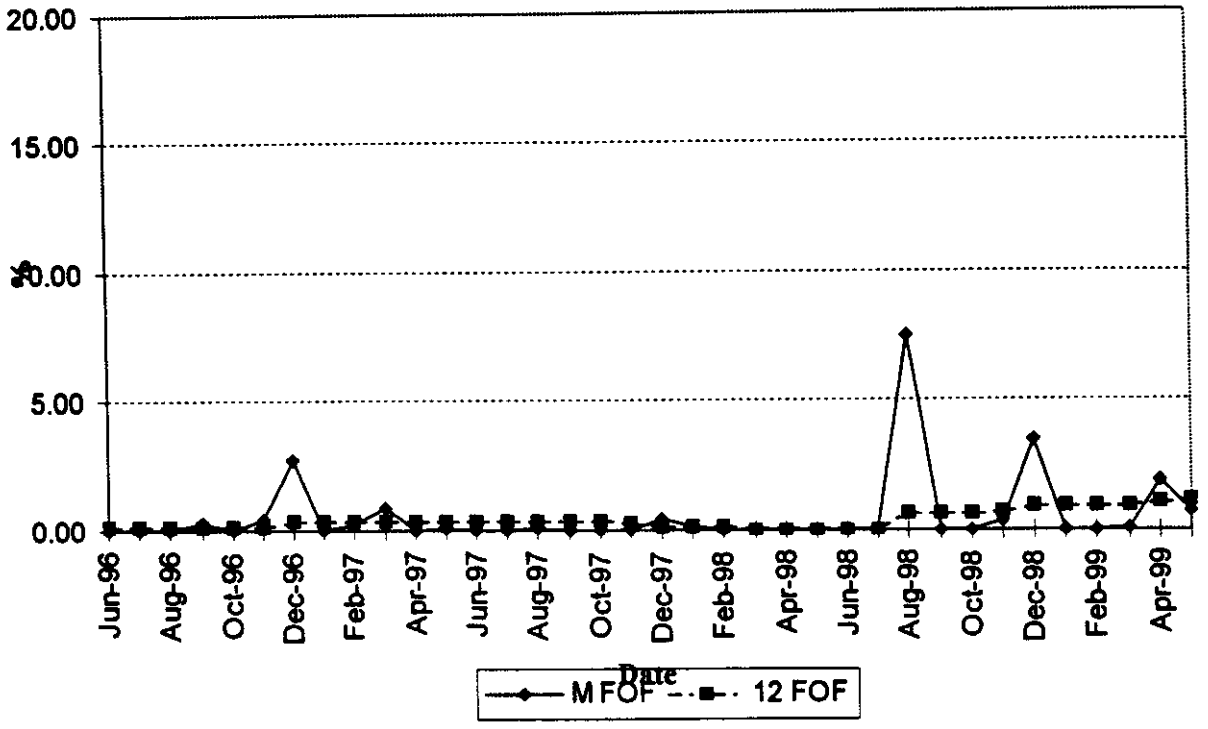
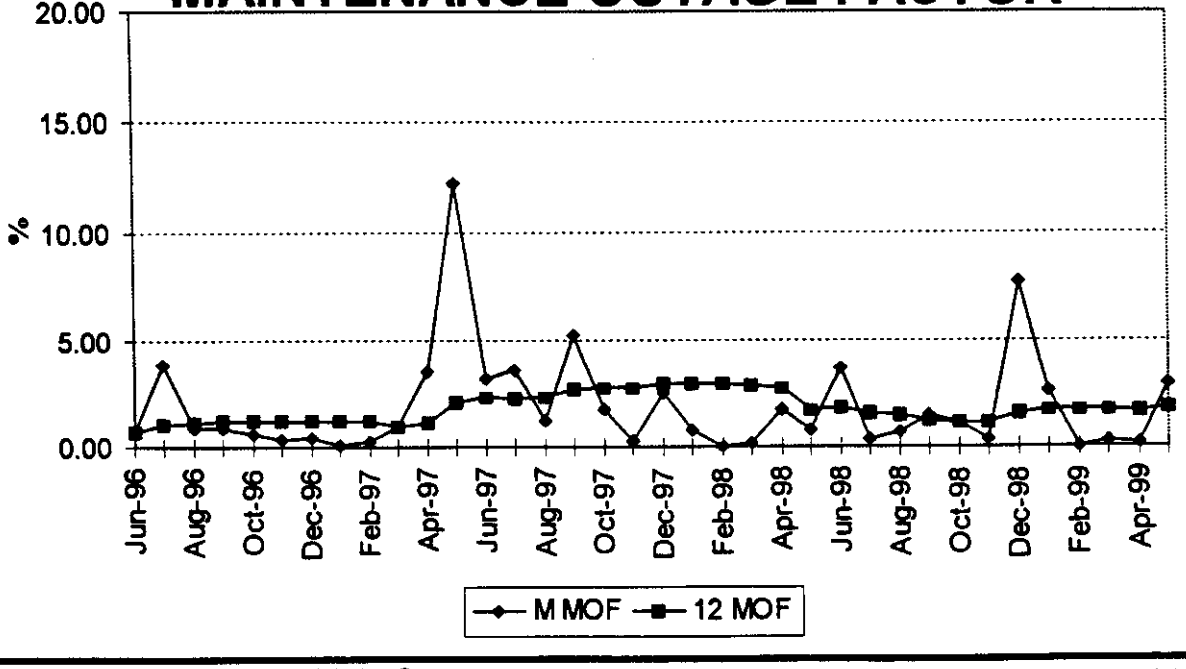


MAINTENANCE OUTAGE FACTOR



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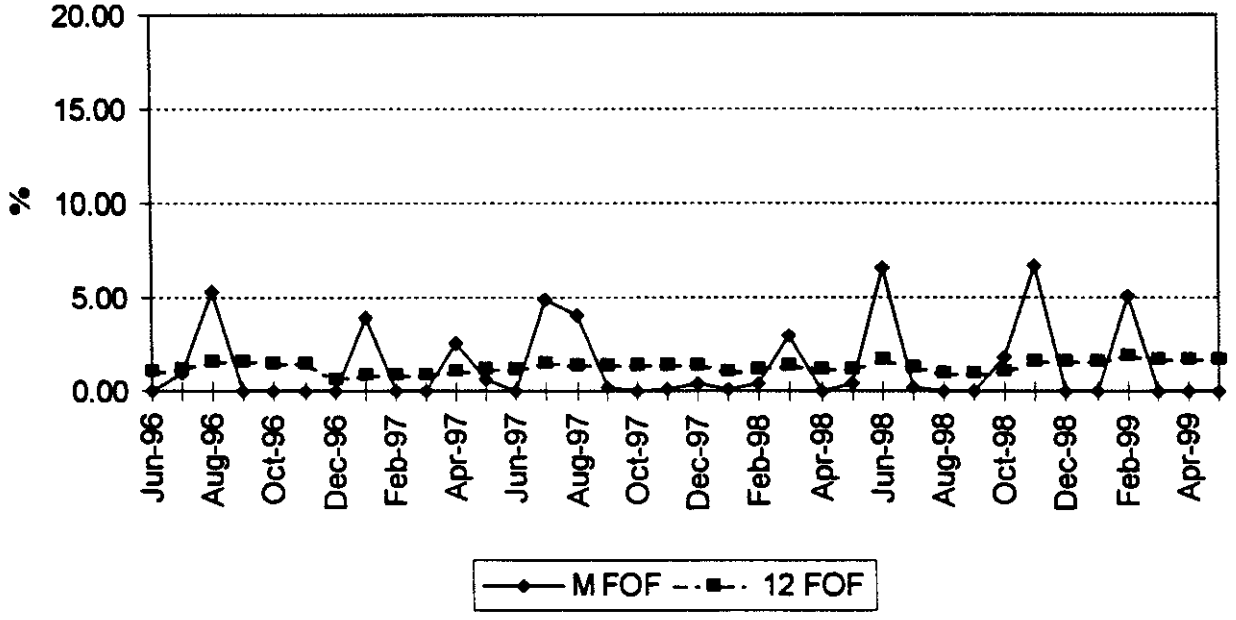
FORCED OUTAGE FACTOR



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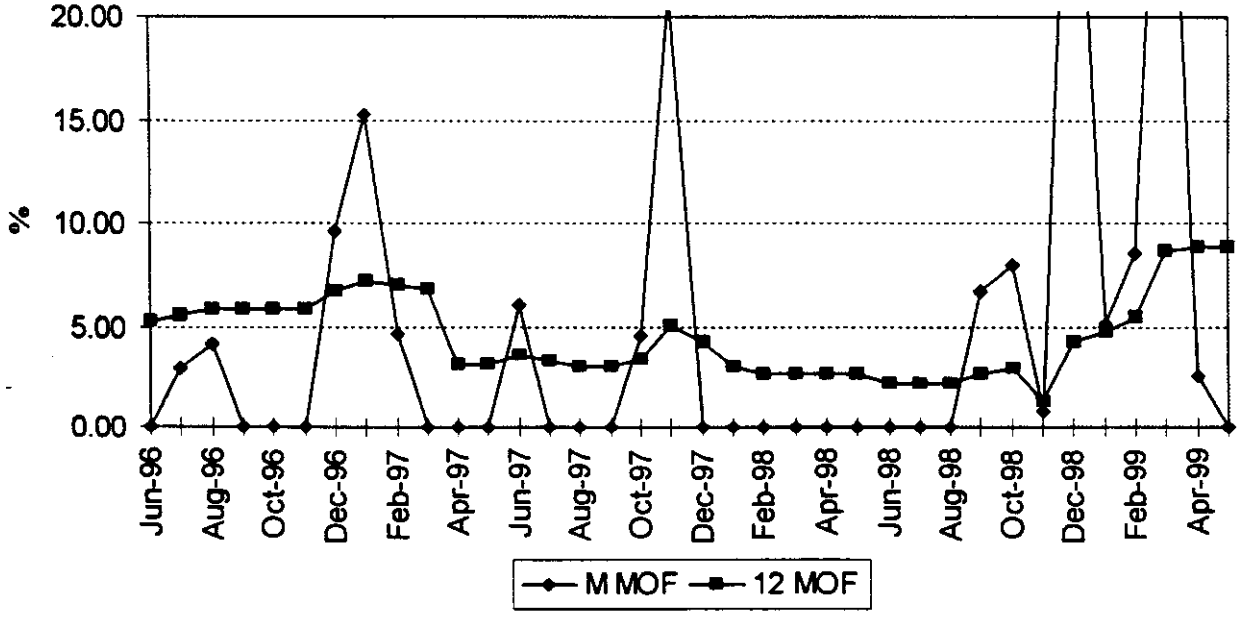

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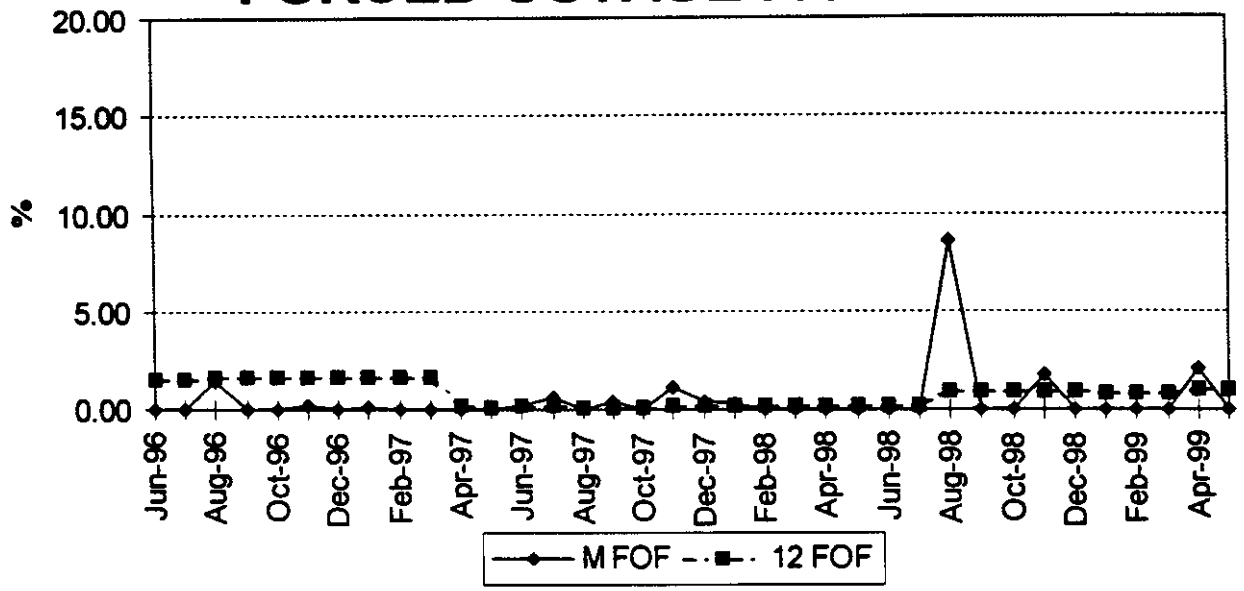
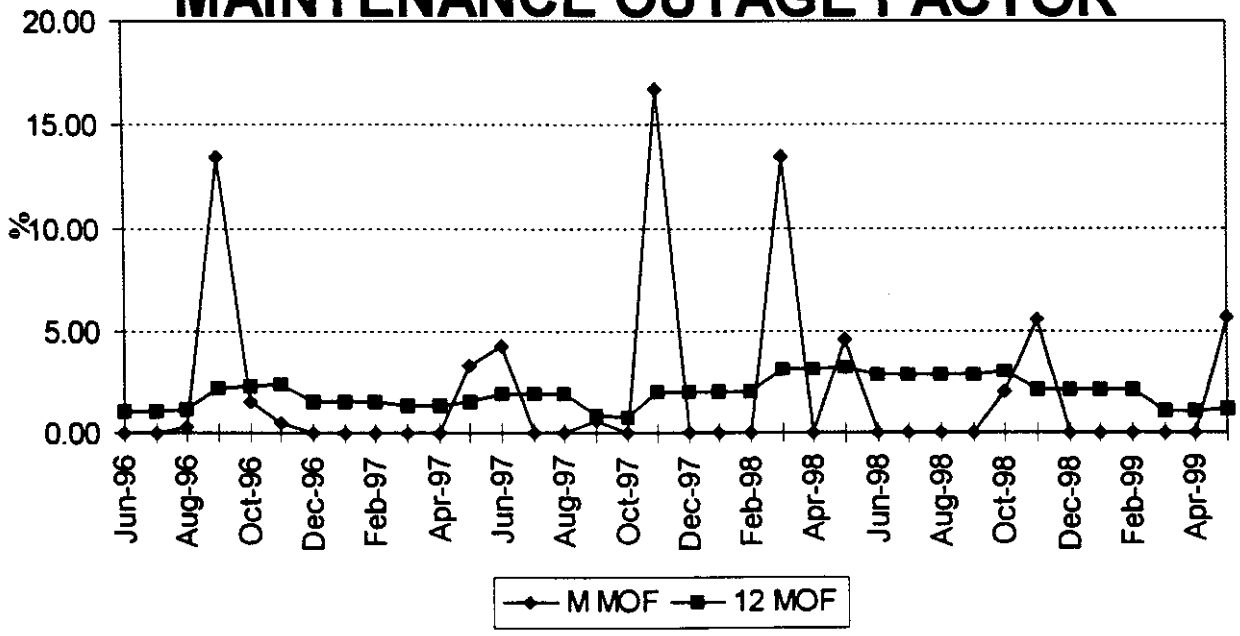
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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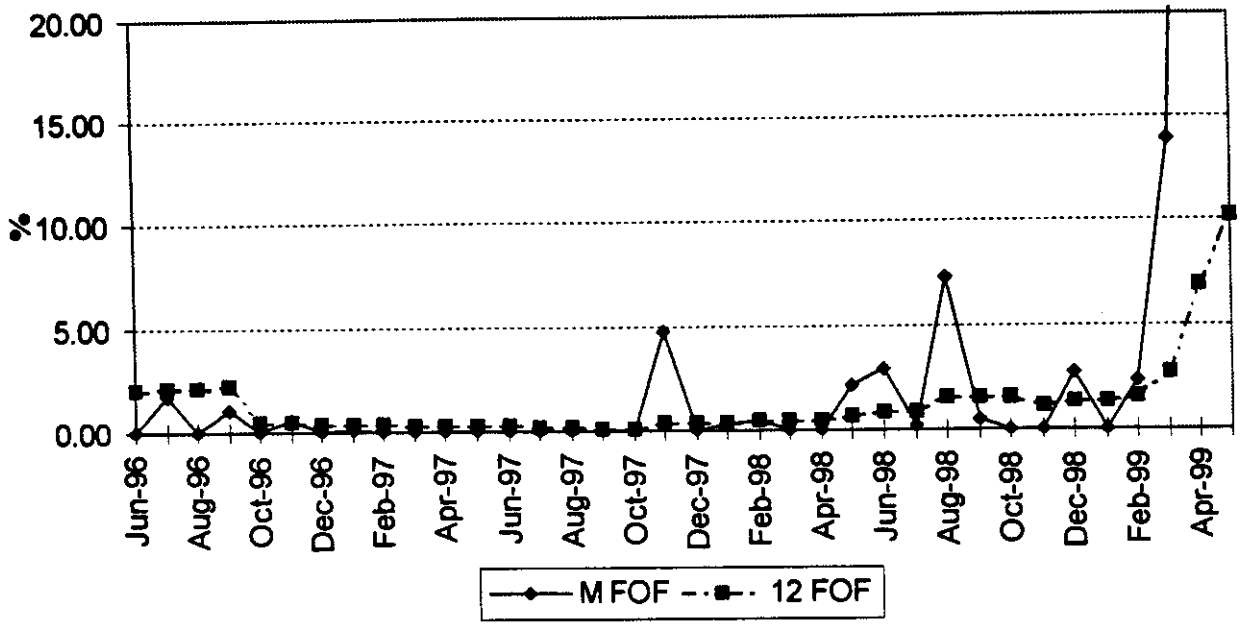

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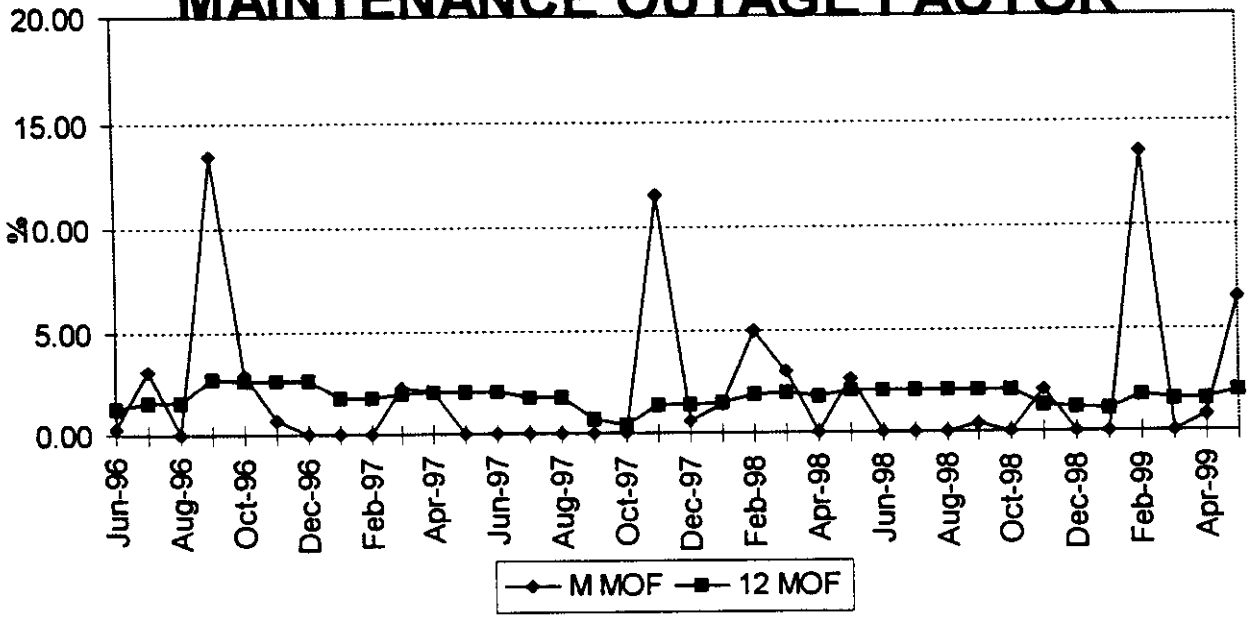

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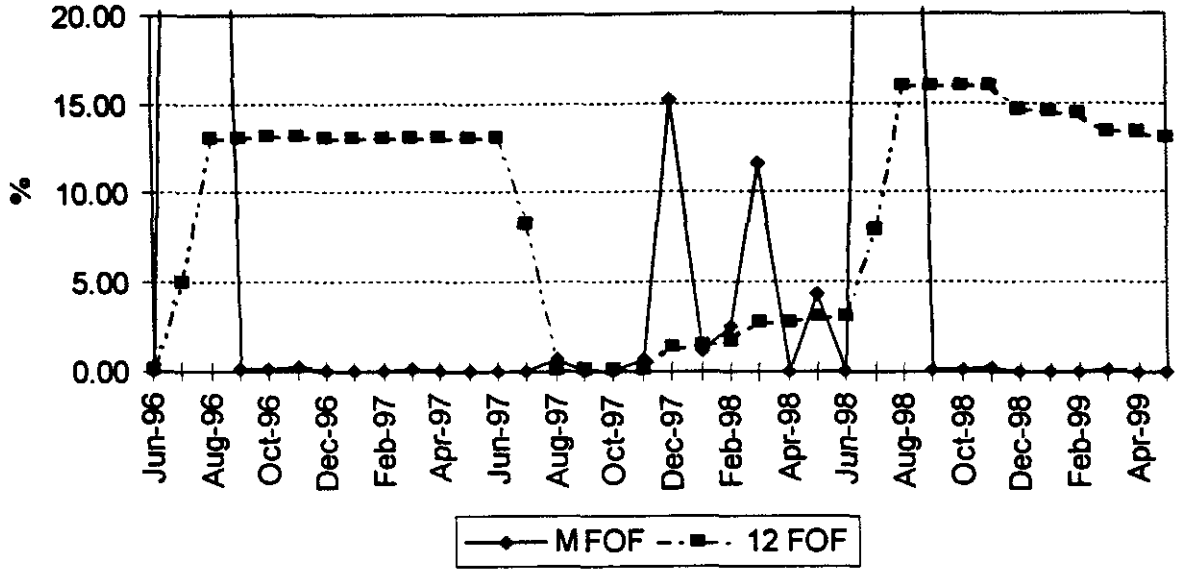

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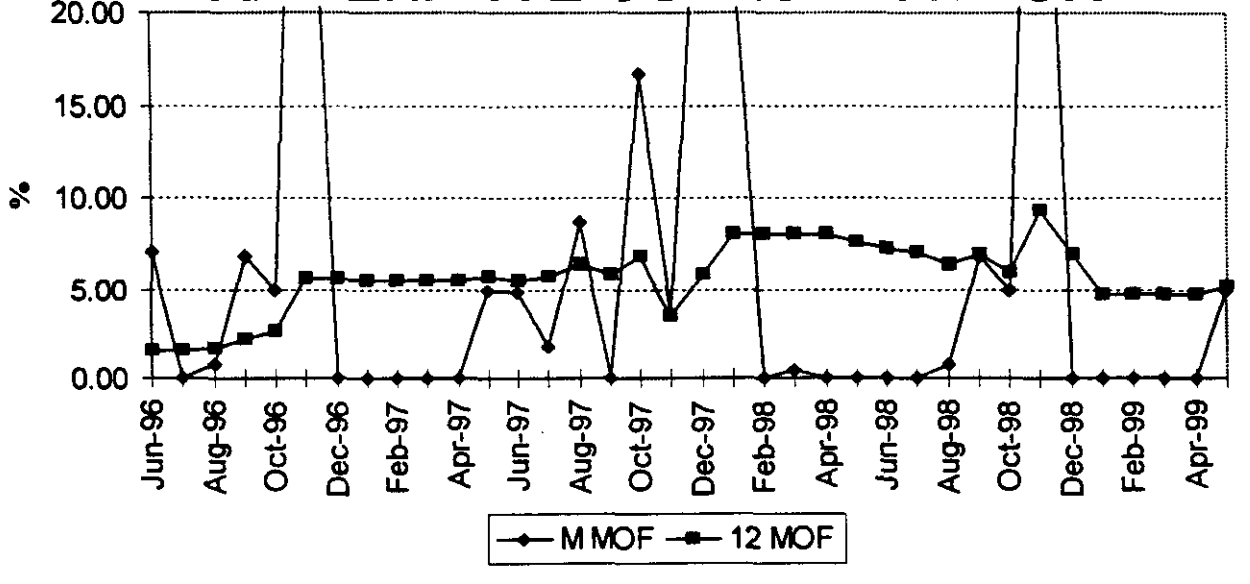

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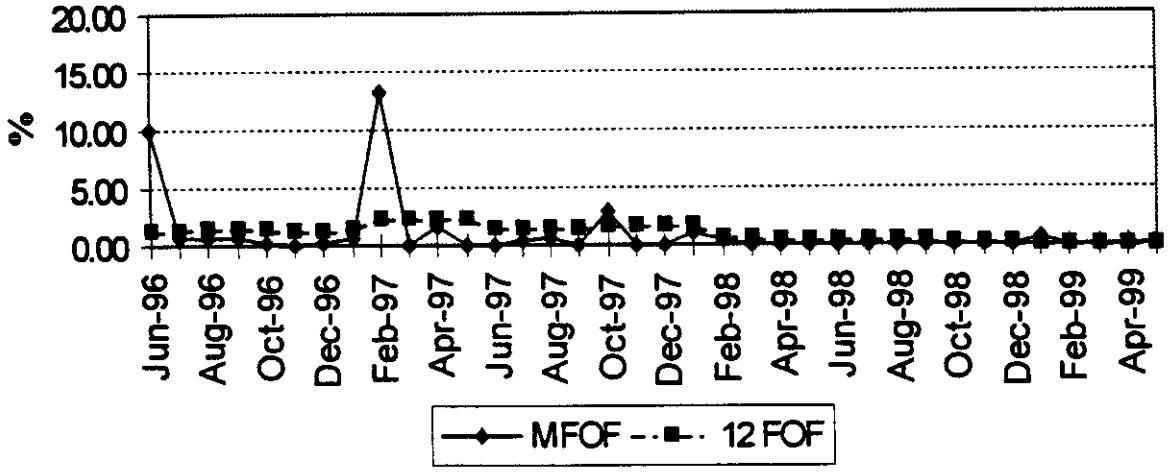
FORCED OUTAGE FACTOR



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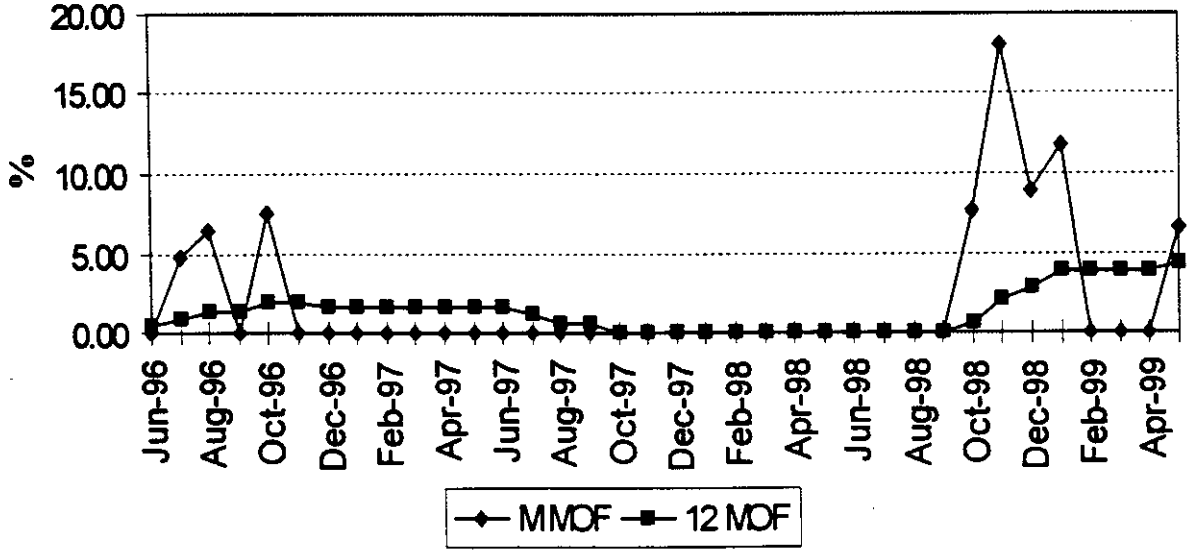

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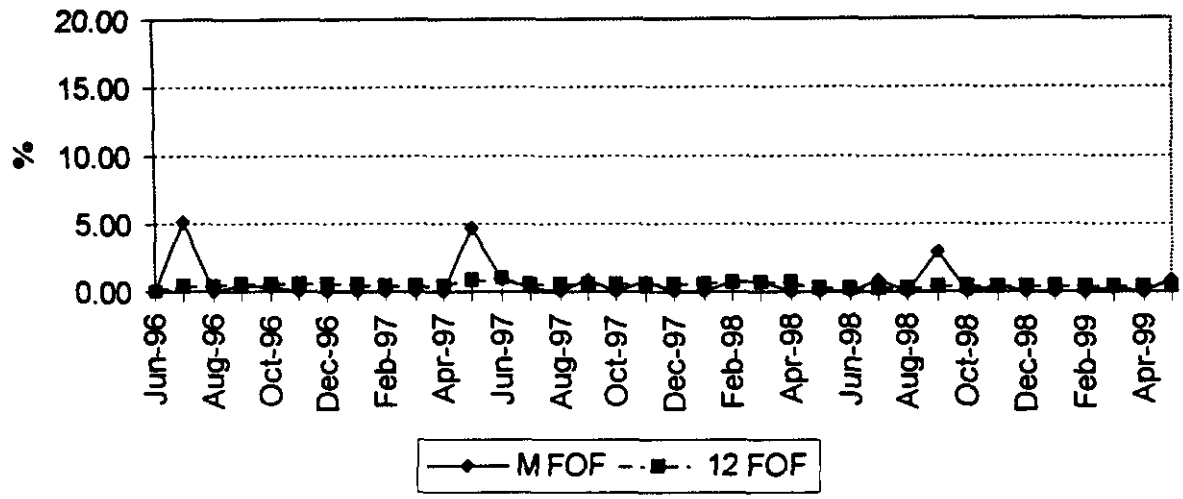

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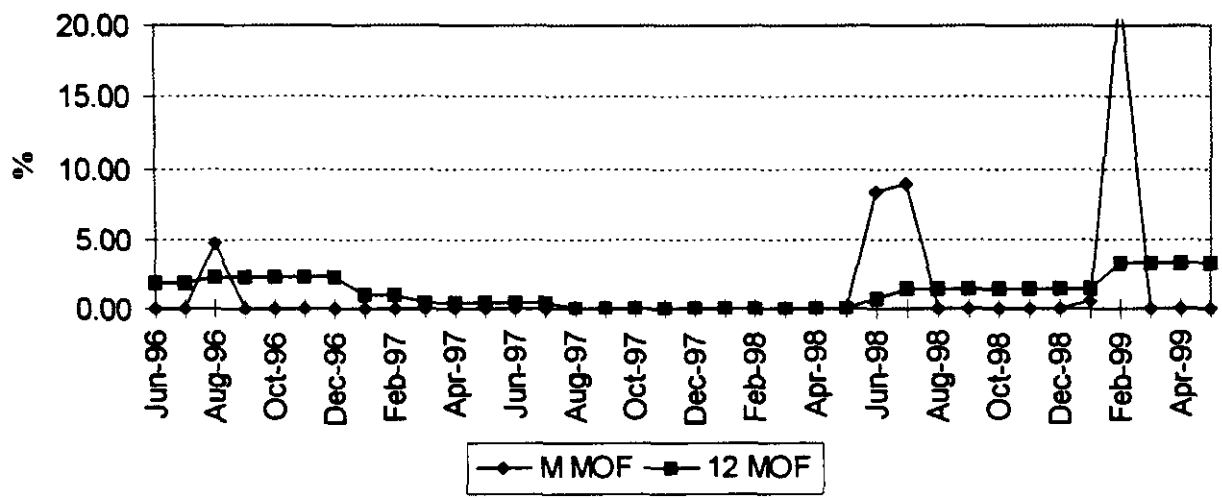

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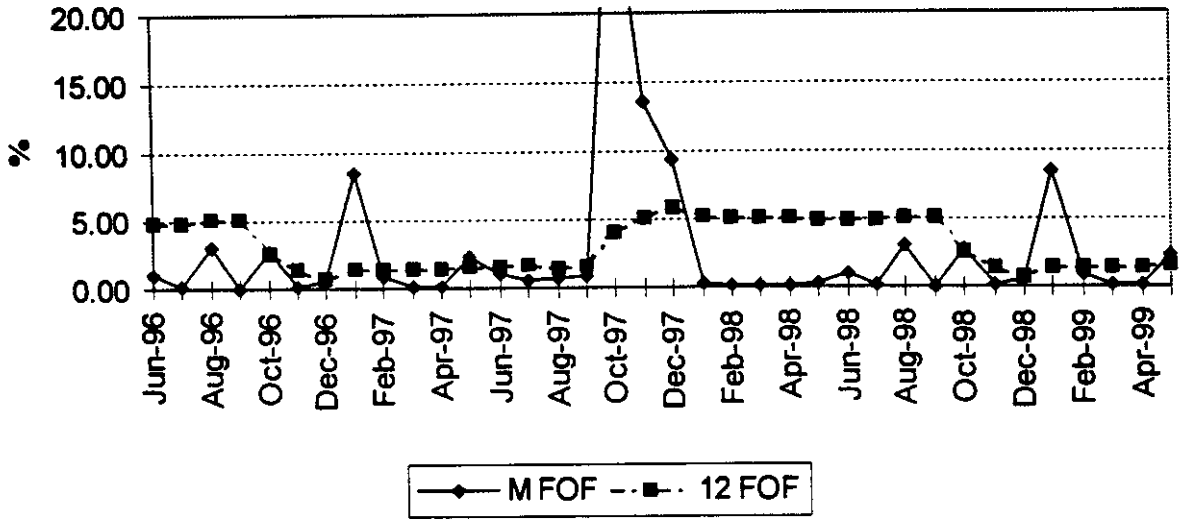

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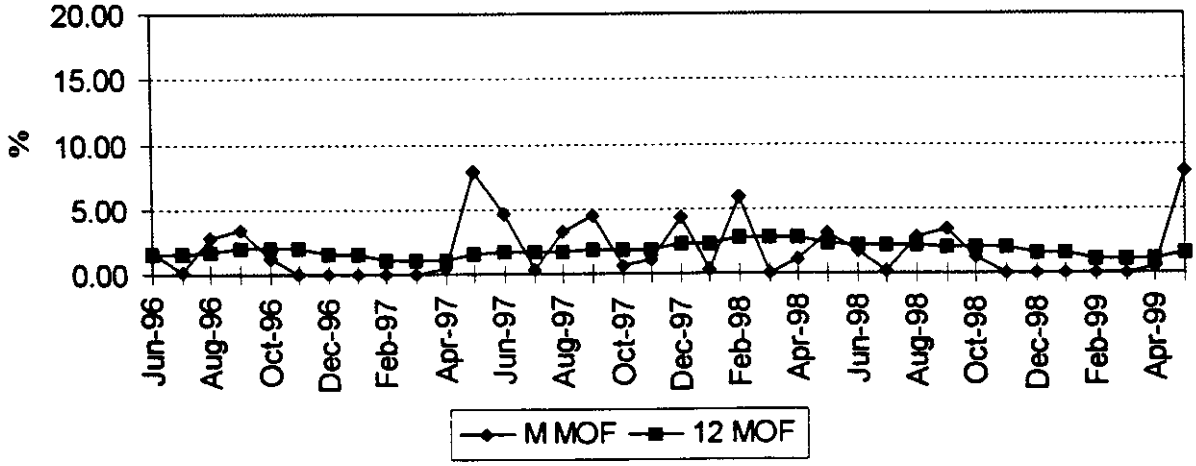

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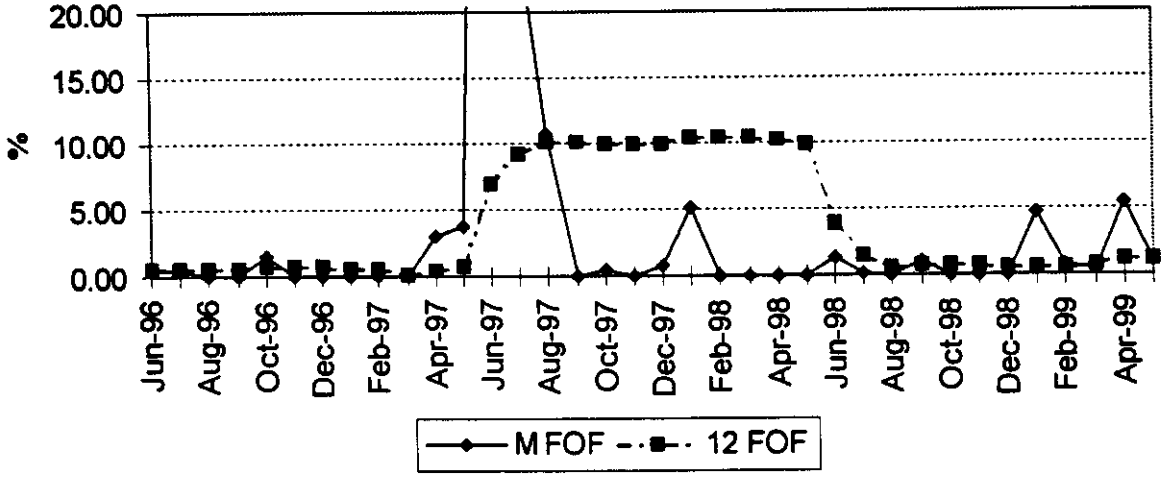

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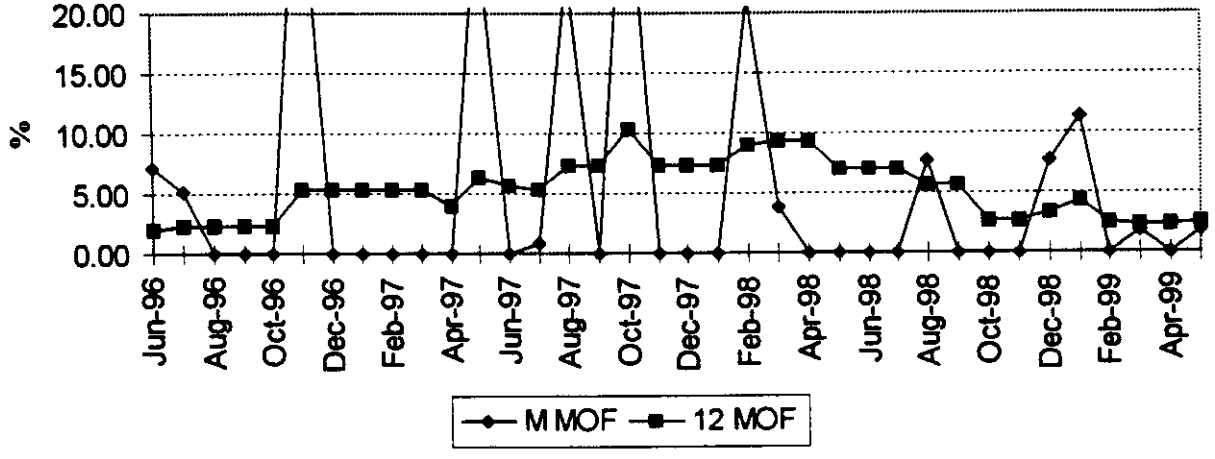

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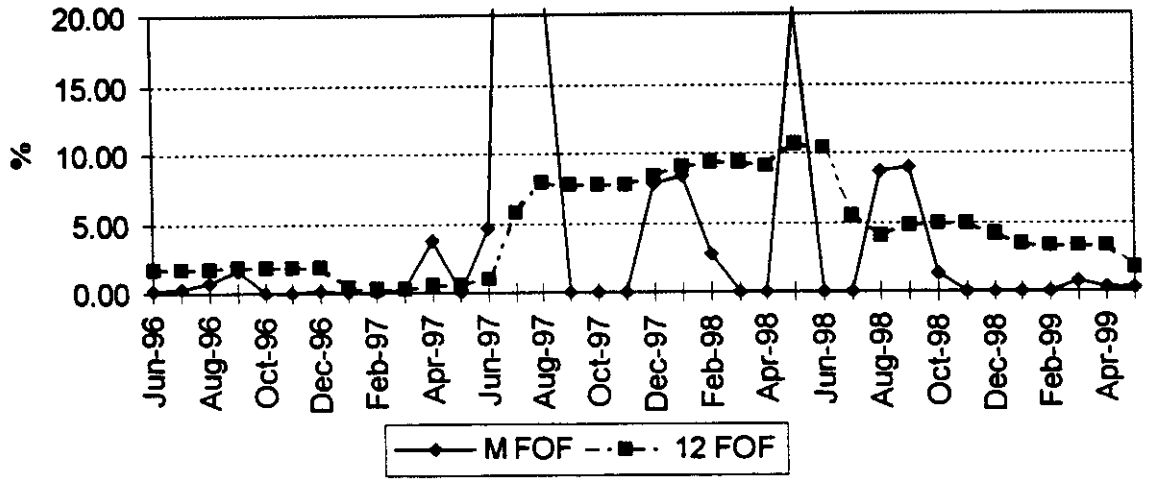

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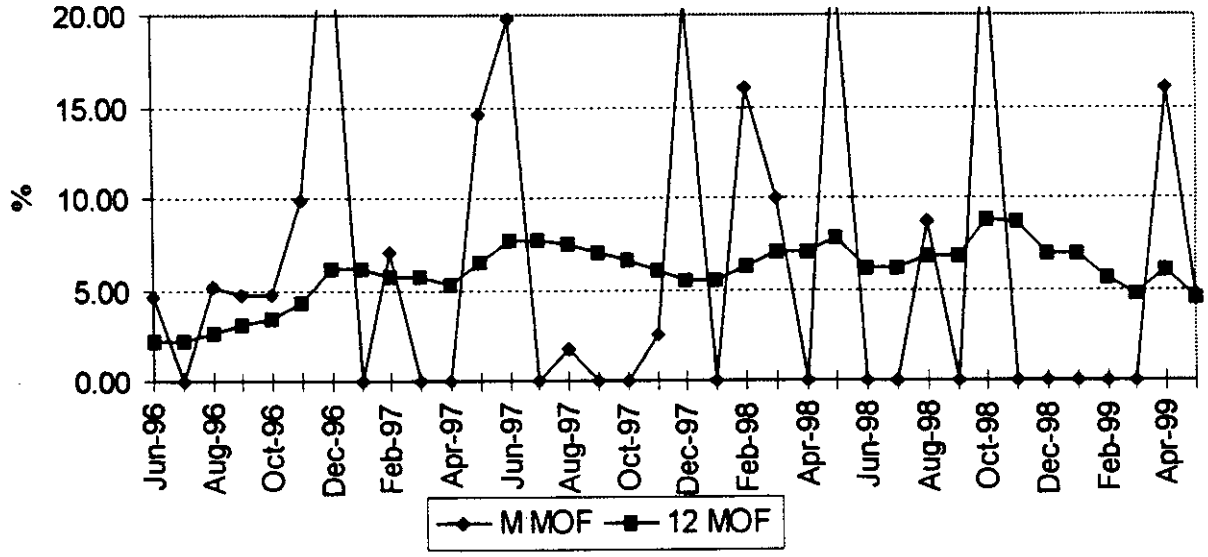

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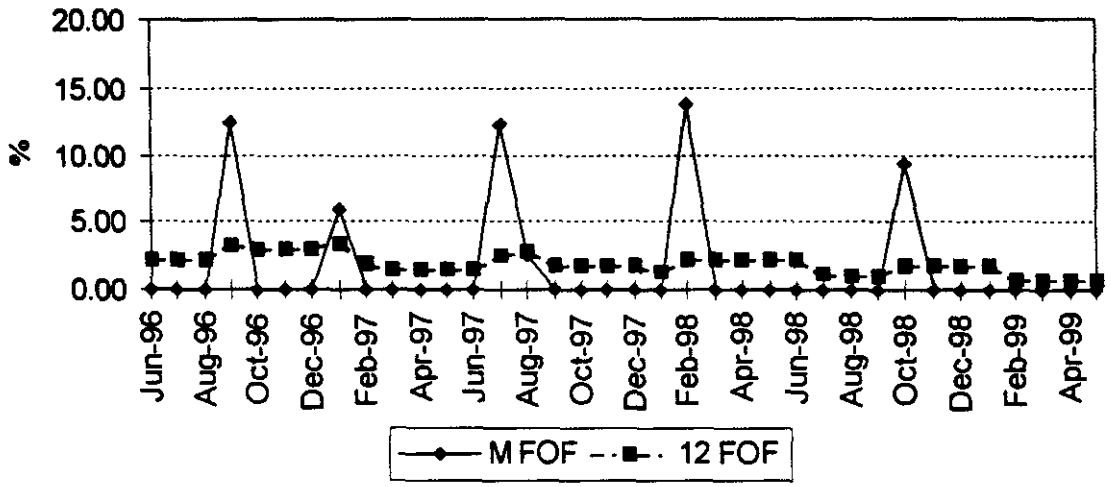

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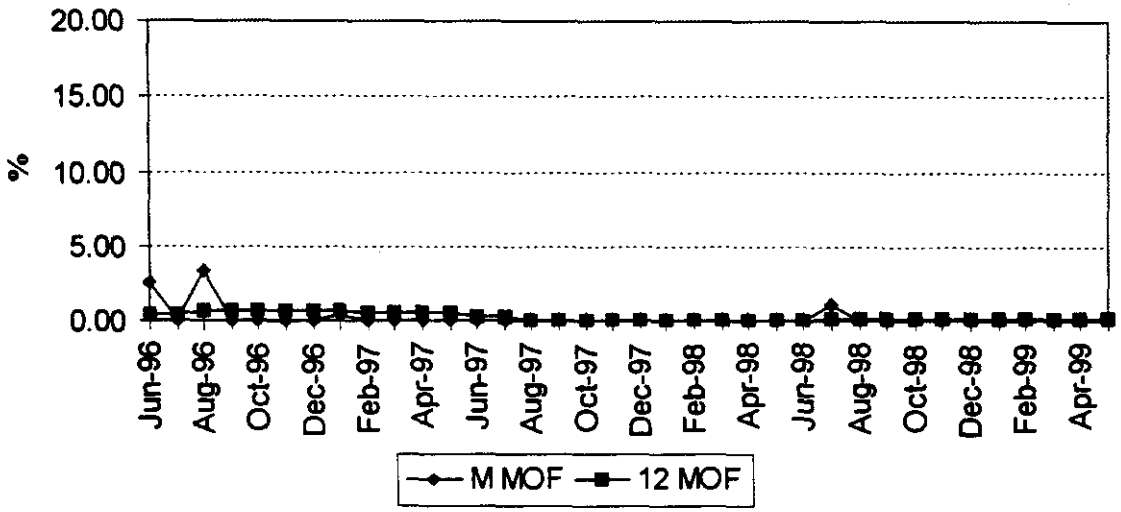

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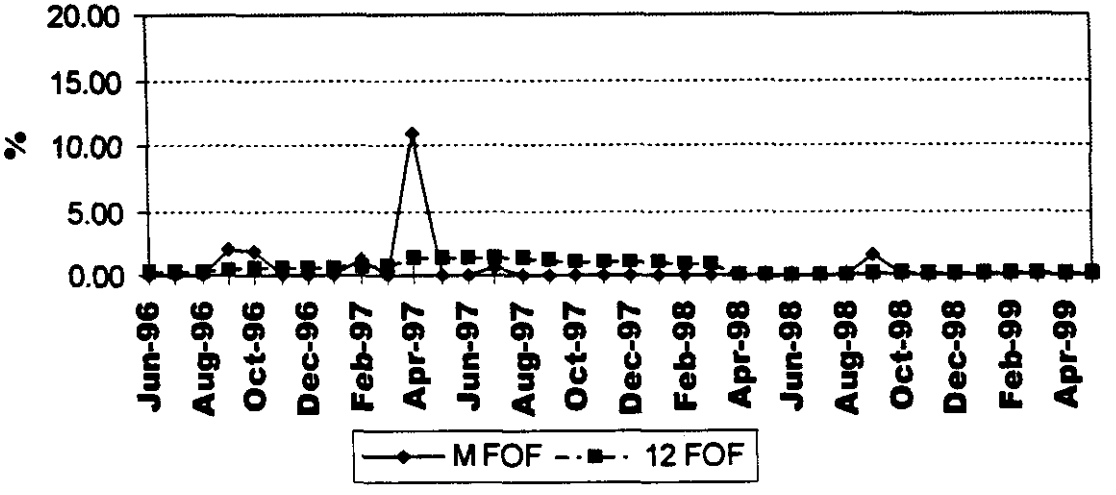

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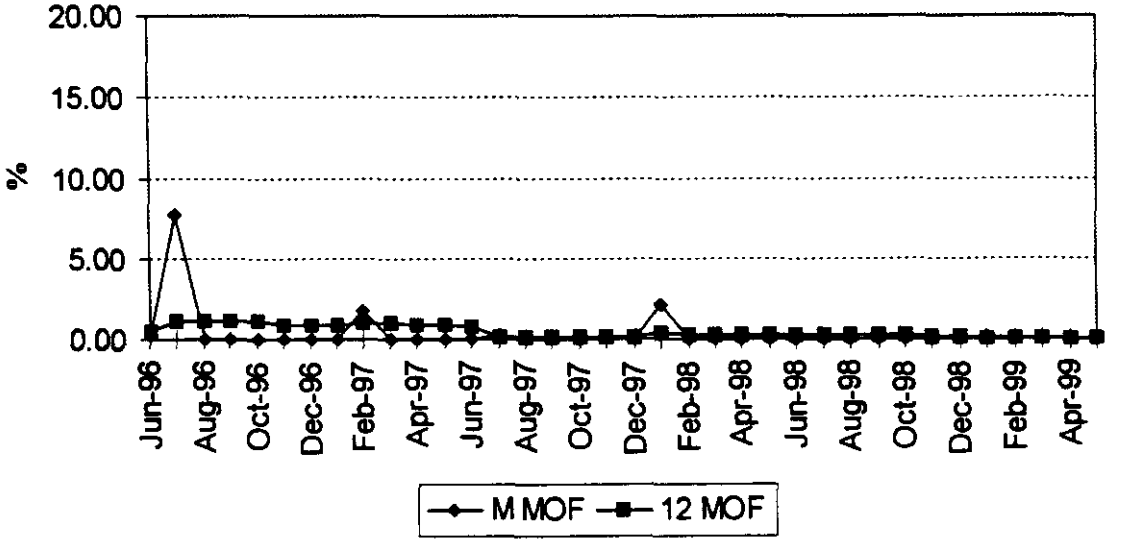

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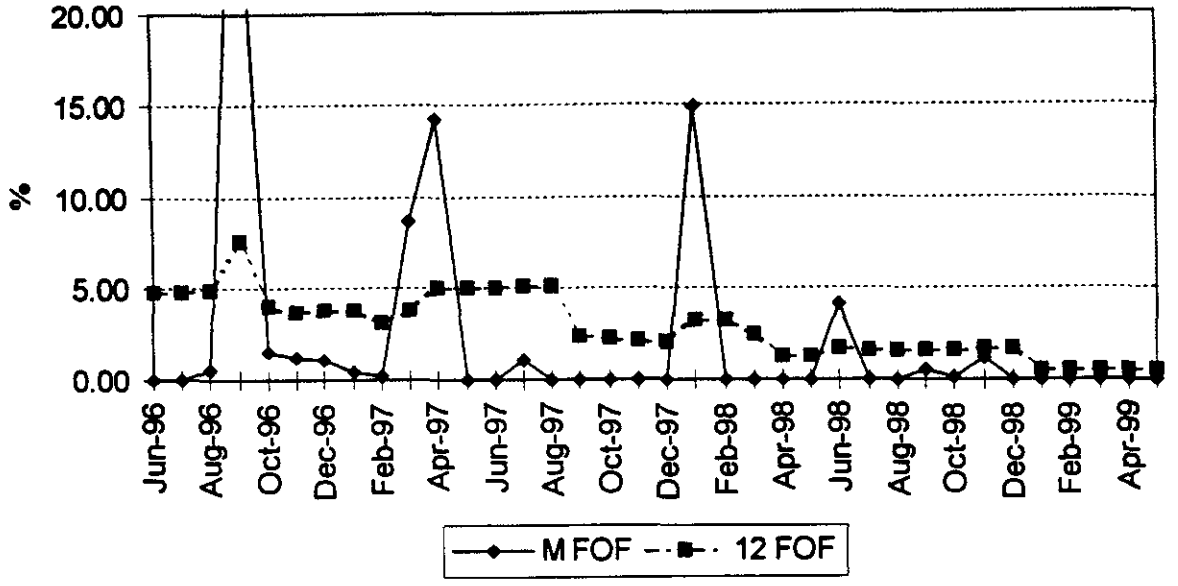

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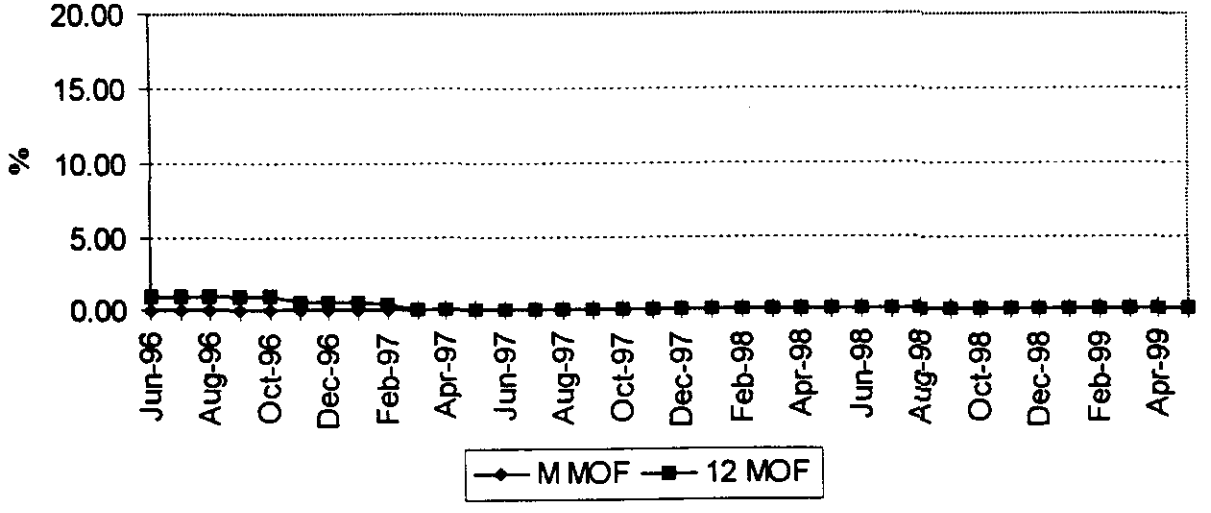

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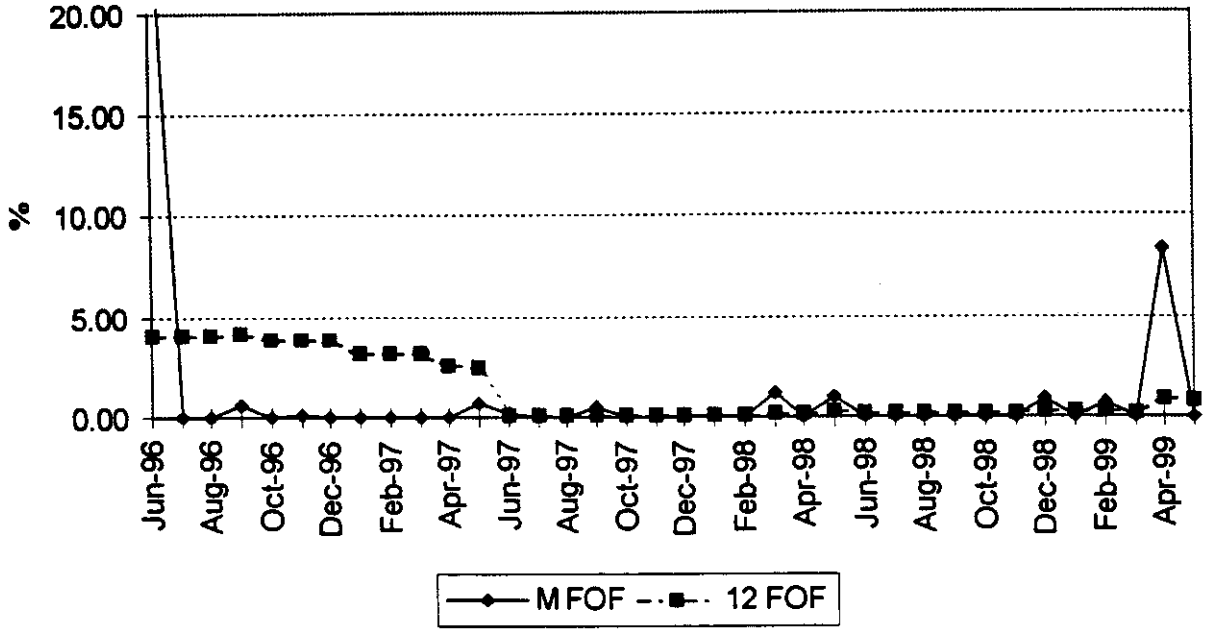

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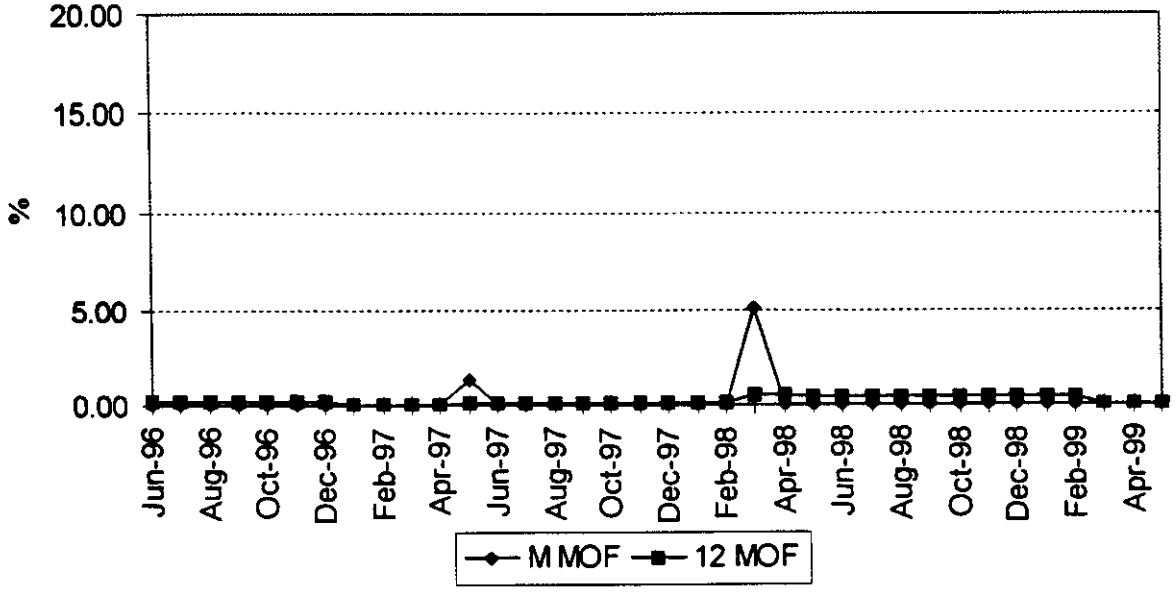

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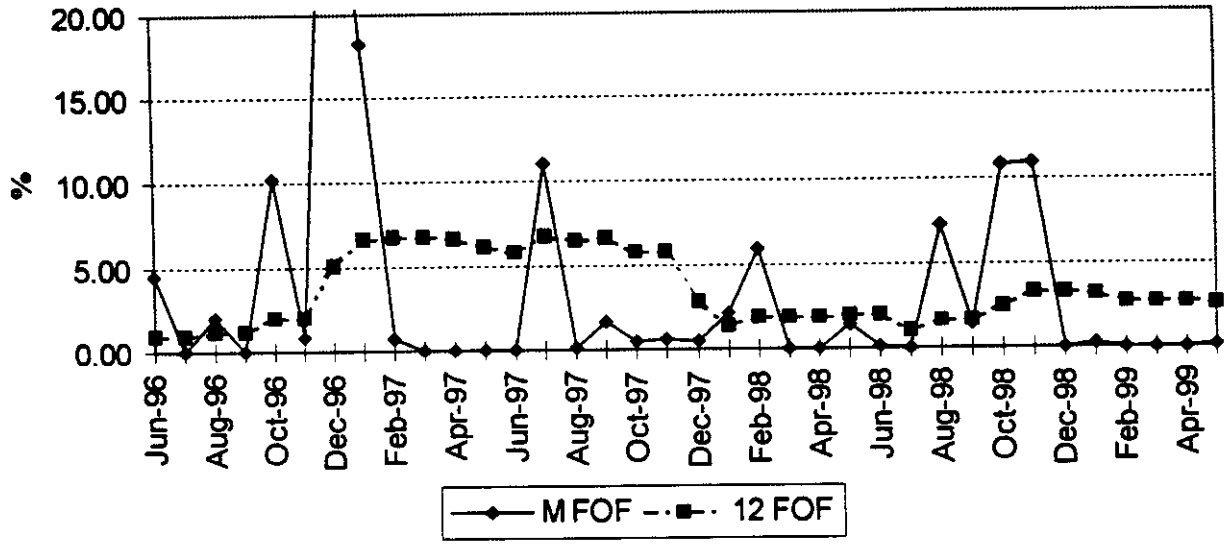
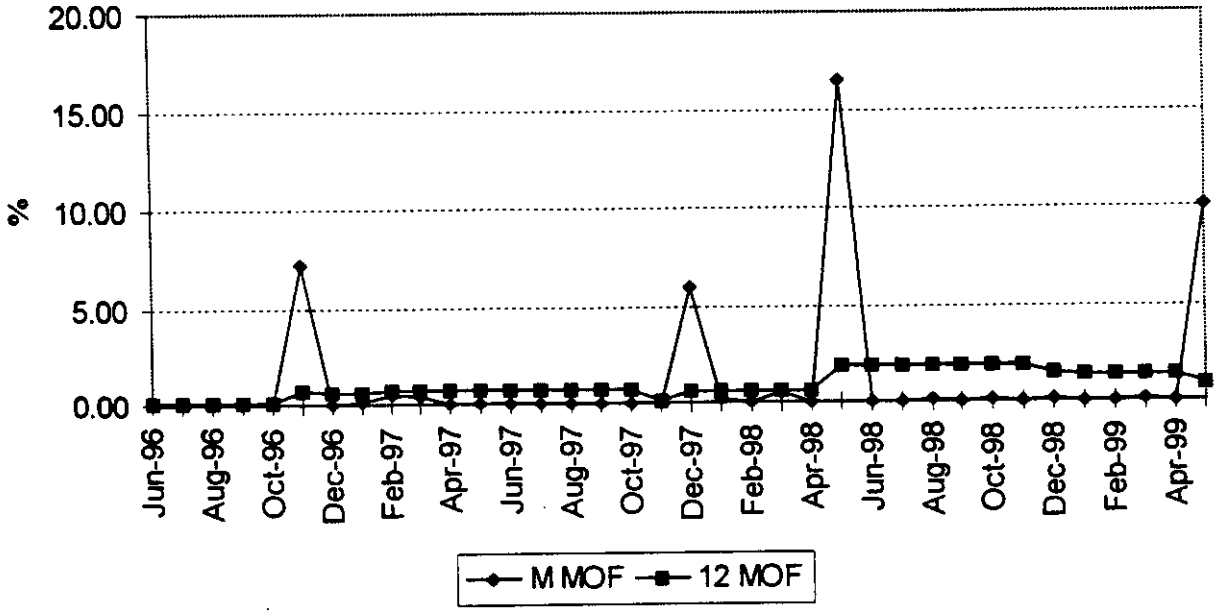
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY 2000 THROUGH DECEMBER 2000

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW
Cape Canaveral 1	NONE		
Cape Canaveral 2	03/11/00 - 05/07/00	Turbine Upgrade	402
Lauderdale 4	03/11/00 - 03/20/00	Combustion Turbine Overhaul	439
Lauderdale 5	03/11/00 - 03/20/00	Combustion Turbine Overhaul	439
Fort Myers 2	NONE		
Manatee 2	09/30/00 - 11/19/00	Turbine/Gen. Overhaul	795
Martin 3	04/01/00 - 04/06/00	Combustion Turbine Overhaul	238
	09/16/00 - 09/22/00	Combustion Turbine Overhaul	238
Martin 4	04/15/00 - 05/05/00	Combustion Turbine Overhaul	238
Port Everglades 3	NONE		
Port Everglades 4	10/14/00 - 11/12/00	Generator Overhaul	402
Putnam 1	11/11/00 - 12/16/00	Combustion Turbine Overhaul	123
Sanford 4	NONE		
Sanford 5	NONE		
Turkey Point 3	02/28/00 - 04/02/00	Refueling Overhaul	703
Turkey Point 4	10/02/00 - 11/05/00	Refueling Overhaul	703
St.Lucie 1	NONE		
St.Lucie 2	04/17/00 - 05/21/00	Refueling Overhaul	845
Scherer 4	NONE		

EXHIBITS TO THE TESTIMONY OF JOHN SCARDINO, JR.

Re: Fuel and Capacity Cost Recovery
Final True-Up Amount for
April 1998 through December 1998

FUEL ADJUSTMENT CLAUSE (JS-1)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 5
COMPANY/ WITNESS: Scardino
DATE: 11-22-99

Florida Power Corporation
Docket No. 990001-EI
Witness: Scardino
Exhibit No. (JS-1)
Sheet 1 of 3

FLORIDA POWER CORPORATION
Fuel Adjustment Clause
Summary of Final True-Up Amount
April 1998 through December 1998

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
1	**KWH Sales:**	
2	Jurisdictional KWH Sales	1,548,425,261
3	Non-Jurisdictional KWH Sales	50,253,752
4	Total System KWH Sales	
5	Schedule A2, pg 2 of 4, Line C1 through C3	1,598,679,013
6		
7	**System:**	
8	Fuel and Net Purchased Power Costs - Difference	
9	Schedule A2, page 3 of 4, Line D4	$ 21,130,772
10		
11	**Jurisdictional:**	
12	Fuel Revenues - Difference	
13	Schedule A2, page 3 of 4, Line D3	$ 22,890,083
14		
15	True Up Provision for the Period Over/(Under)	
16	Collection - Estimated	
17	Schedule A2, page 3 of 4, Line D7	14,915,528
18		
19	Net Fuel Revenues	37,805,611
20		
21		
22	Fuel and Net Purchased Power Costs - Difference	
23	Schedule A2, page 3 of 4, Line D6	20,438,106
24		
25	True Up Amount for the Period	17,367,505
26		
27	True Up for the Prior Period - Actual	
28	Schedule A2, page 3 of 4, Line D9+D10	4,971,580
29		
30	Interest Provision - Actual	
31	Schedule A2, page 3 of 4, Line D8	(743,687)
32		
33	Actual True Up ending balance for the period	
34	April 1998 through December 1998	21,595,398
35		
36	Estimated True Up ending balance for the period included in	
37	filing of Levelized Fuel Cost Factors January through December 1999,	
38	Docket No. 980001-EI, Schedule E1-B, Sheet 1, Line 20	6,491,587
39		
40	Final True Up for the period April 1998 through	
41	December 1998 (Line 34 - Line 36)	$ 15,103,811

FLORIDA POWER CORPORATION
Docket No. 990001-EI
Witness: Scardino
Exhibit No. ____ (JS-1)
Sheet 2 of 3

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: APRIL - DECEMBER 1998

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	$67,636,504	$1,110,222	($25,341,292)	$43,405,434
2	Light Oil	42,576,274	(7,713,730)	(6,235,100)	28,627,444
3	Coal	(11,502,520)	210,777	1,382,126	(9,909,617)
4	Gas	32,985,786	5,792,213	(4,004,490)	34,773,509
5	Nuclear	1,083,108	(411,839)	307,521	978,790
6	Other Fuel	0	0	0	0
7	Total Generation	132,779,152	(1,012,357)	(33,891,235)	97,875,560
8	Firm Purchases	3,506,106	0	445,717	3,951,823
9	Economy Purchases	(2,378,111)	0	15,853,065	13,474,954
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(20,444,994)	0	(7,927,650)	(28,372,644)
12	Total Purchases	(19,316,999)	0	8,371,132	(10,945,867)
13	Economy Sales	9,208,379	0	259,851	9,468,230
14	Other Power Sales	(35,347,292)	0	290,126	(35,057,166)
15	Supplemental Sales	(6,696,777)	0	(6,129,822)	(12,826,599)
16	Total Sales	(32,835,690)	0	(5,579,845)	(38,415,535)
17	Nuclear Fuel Disposal Cost	0	0	275,605	275,605
18	Nuclear Decom & Decon	0	0	23,670	23,670
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	(26,035,327)	0	(1,647,334)	(27,682,661)
20	Total Fuel and Net Power	$54,591,136	($1,012,357)	($32,448,007)	$21,130,772

FLORIDA POWER CORPORATION
Docket No. 990001-E1
WITNESS: SCARDINO
EXHIBIT NO. (JS-1)
Sheet 3 of 3

GAS CONVERSION PROJECTS
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD APRIL, 1998 THROUGH DECEMBER, 1998

		INTERCESSION CITY 7 & 9	INTERCESSION CITY 8 & 10	DEBARY 7 & 9	BARTOW 2 & 4	SUWANNEE 1 & 3	TOTAL
	PLANT INVESTMENT						
1	BEGINNING BALANCE	$ 2,340,875	$ 1,646,809	$ 3,329,542	$ 2,444,925	$ 1,663,304	$ 11,425,455
2	ADD INVESTMENT	-	-	22,715	-	1,797,256	1,819,971
3	LESS RETIREMENTS	-	-	-	-	-	-
4	ENDING BALANCE	2,340,875	1,646,809	3,352,257	2,444,925	3,460,560	13,245,426
5							
6	ACCUMULATED DEPRECIATION						
7	BEG. BALANCE ACCUM. DEPRECIATION	1,125,299	525,304	461,298	342,849	203,792	2,658,542
8	DEPRECIATION EXPENSE	351,135	247,023	500,754	366,732	427,674	1,893,318
9	LESS RETIREMENTS	-	-	-	-	-	-
10	END. BALANCE ACCUM. DEPRECIATION	1,476,434	772,327	962,052	709,581	631,466	4,551,860
11							
12							
13	ENDING NET INVESTMENT (LINE 4-10)	$ 864,441	$ 874,482	$ 2,390,205	$ 1,735,344	$ 2,829,094	$ 8,693,566
14							
15	TOTAL RETURN REQUIREMENTS	90,365	86,718	228,277	166,712	213,822	$ 785,894
16							
17	TOTAL ACCUMULATED DEPRECIATION						
18	AND RETURN (LINE 8+ 15)	$ 441,500	$ 333,741	$ 729,031	$ 533,444	$ 641,496	$ 2,679,212
19							
20							
21	ESTIMATED FUEL SAVINGS	2,122,456	1,917,183	4,650,322	988,158	1,936,488	11,614,607
22							
23	TOTAL DEPRECIATION & RETURN (1)	441,500	333,741	729,031	533,444	641,496	2,679,212
24							
24	NET BENEFIT (COST) TO RATEPAYER	$ 1,680,956	$ 1,583,442	$ 3,921,291	$ 454,714	$ 1,294,992	$ 8,935,395
25							
25							
26							

27 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
28 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%). THIS IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 91-0890-EI.
29 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%
30 (1) TOTAL AMOUNT DIFFERS FROM SCHEDULE A-2, PAGE 1 OF 4, LINE 6b BECAUSE A-2 EXCLUDES COST ASSIGNED TO SUPPLEMENTAL KWH SALES.

6

EXHIBITS TO THE TESTIMONY OF JOHN SCARDINO, JR.

Re: Fuel and Capacity Cost Recovery
Final True-Up Amount for
April 1998 through December 1998

CAPACITY COST RECOVERY CLAUSE (JS-2)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 6
COMPANY/ WITNESS: Scardino
DATE: 11-22-99

Florida Power Corporation
Docket No. 990001-EI
Witness: Scardino
Exhibit No. (JS-2)
Sheet 1 of 3

FLORIDA POWER CORPORATION
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
April 1998 through December 1998

Line No.	Description	Actual	Original Estimate	Variance
1				
2	**Jurisdictional:**			
3	Capacity Cost Recovery Revenues			
4	Sheet 2 of 3, *Column J*, Line 38	$ 222,675,827	$ 219,336,759	$ 3,339,068
5				
6	Capacity cost Recovery Expenses			
7	Sheet 2 of 3, Column J, Line 34	216,588,771	219,336,759	$ (2,747,988)
8				
9	*Plus/(Minus) Interest Provision*			
10	Sheet 2 of 3, Column J, Line 40	(17,022)	98,750	$ (115,772)
11				
12	Sub Total Current Period Over/(Under) Recovery	$ 6,070,034	$ 98,750	$ 5,971,284
13				
14	Prior Period True-up - *October 1997 through*			
15	March 1998 - Over/(Under) Recovery			
16	Sheet 2 of 3, Column J, Line 42 + Line 44	1,695,400	1,840,750	(145,350)
17				
18	Prior Period True-up (Refunded)/Collected			
19	Sheet 2 of 3, Column F, Line 43 - Line 44	(1,695,400)	(1,840,750)	145,350
20	April through September 1998			
21				
22	Prior Period True-up (Refunded)/Collected			
23	Sheet 2 of 3, Column G, Line 43 - Line 44			
24	October through December 1998	(5,847,915)	-	(5,847,915)
25				
26	*Actual True-up ending balance Over/(Under) recovery*			
27	for the period April 1998 through December 1998			
28	Sheet 2 of 3, Column G, Line 45	$ 222,119	$ 98,750	$ 123,369
29				
30	Estimated True-up ending balance for the			
31	period included in the filing of Levelized			
32	Fuel Cost Factors January 1999 through December 1999			
33	Docket No. 980001 - E1, Part D,			
34	Sheet 2 of 6, Line 34	(4,856,714)		
35				
36	Final Over/(Under) Recovery for the period *April 1998*			
37	through December 1998 (Line 28 - Line 34)	$ 5,078,833		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

Florida Power Corporation
Docket 990001-EI
Witness: Scardino
Exhibit No. (JS-2)
Sheet 2 of 3

	Description	(A) 1998 APRIL	(B) 1998 MAY	(C) 1998 JUNE	(D) 1998 JULY	(E) 1998 AUGUST	(F) 1998 SEPTEMBER	(G) 1998 OCTOBER	(H) 1998 NOVEMBER	(I) 1998 DECEMBER	(J) 9 Months Cumulative
	Base Production Level Capacity Charges:										
1	Auburndale Power Partners, L.P. (AUBRDLAS)	0	0	0	0	0	0	0	0	0	$0
2	Auburndale Power Partners, L.P (AUBRDLFC)	511,480	511,480	511,480	511,480	511,480	511,480	511,480	327,930	$327,930	$4,236,220
3	Auburndale Power Partners, L.P. (AUBSET)	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	1,712,053	$15,408,481
4	Bay County (BAYCOUNT)	162,360	162,360	162,360	162,360	162,360	162,360	162,360	162,360	162,360	$1,461,240
5	Cargill Fertilizer, Inc. (CARGILLF)	354,900	353,266	348,428	344,405	337,622	328,844	338,615	354,900	354,900	$3,115,880
6	Lake Cogen Limited (LAKECOGL)	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	1,827,325	$16,445,928
7	Lake County (LAKCOUNT)	307,403	307,403	307,403	307,403	307,403	307,403	307,403	307,403	307,403	$2,766,623
8	Metro-Dade County (METRDADE)	490,213	486,642	492,103	488,578	489,173	514,391	511,959	586,950	577,897	$4,637,907
9	Orange Cogen (ORANGECO)	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	1,552,277	1,549,132	$13,967,352
10	Orlando Cogen Limited (ORLACOGL)	1,365,094	1,365,094	1,365,094	1,365,094	1,365,094	1,201,283	1,365,094	1,365,094	1,365,094	$12,122,036
11	Pasco Cogen Limited (PASCOGL)	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	2,803,012	$25,227,111
12	Pasco County Resource Recovery (PASCOUNT)	554,530	554,530	554,530	554,530	554,530	554,530	554,530	554,530	554,530	$4,990,770
13	Pinellas County Resource Recovery (PINCOUNT)	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	1,320,023	$11,880,203
14	Polk Power Partners, L. P. (MULBERY)	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	1,983,817	$17,854,352
15	Polk Power Partners, L. P. (ROYSTER)	710,101	710,101	710,101	710,101	710,101	710,101	710,101	710,101	710,101	$6,390,909
16	Tiger Bay Limited Partnership (ECOPEAT)	949,402	949,402	949,402	949,402	949,402	949,402	949,402	949,402	949,402	$8,544,618
17	Tiger Bay Limited Partnership (GENPEAT)	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	3,310,164	$29,791,476
18	Tiger Bay Limited Partnership (TIMBER2)	115,740	115,740	115,740	115,740	115,740	115,740	115,740	115,740	115,740	$1,041,660
19	Timber Energy Resources, Inc. (TIMBER)	308,530	325,125	325,125	325,125	325,125	325,125	325,125	325,125	325,125	$2,909,527
20	U.S. Agri-Chemicals (AGRICHEM)	34,109	34,109	34,109	34,109	34,109	34,109	34,109	34,109	34,109	$306,979
21	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	$7,208,512
22	Tiger Bay (EcoPeat lease credit)	(402,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(241,667)	($1,111,003)
23	UPS Purchase (409 total mw)	5,238,601	4,430,843	4,493,427	4,256,823	4,407,466	4,430,843	4,341,745	4,340,885	4,338,742	$40,279,375
24	Subtotal - Base Level Capacity Charges	26,009,413	25,549,044	25,612,252	25,368,100	25,512,555	25,388,561	25,470,613	25,377,479	25,188,137	229,476,153
25	Base Production Jurisdictional Responsibility	96.110%	96.110%	96.110%	96.110%	96.110%	96.110%	96.110%	96.110%	96.110%	96.110%
26	Base Level Jurisdictional Capacity Charges	24,997,647	24,555,187	24,615,936	24,381,281	24,520,116	24,400,948	24,479,806	24,390,295	24,208,318	220,549,532
	Intermediate Production Level Capacity Charges:										
27	TECO Power Purchase (50 mw)	471,367	471,367	471,367	471,367	471,367	471,367	471,387	471,387	471,387	4,242,303
28	Schedule H Capacity Sales	(2,576)	(2,479)	(2,399)	(2,662)	(2,662)	(2,576)	(2,662)	(2,576)	(2,662)	(23,254)
29	Subtotal - Intermediate Level Capacity Charges	468,791	468,888	468,968	468,705	468,705	468,791	468,705	468,791	468,705	4,219,049
30	Intermediate Production Jurisdict. Responsibility	73.773%	73.773%	73.773%	73.773%	73.773%	73.773%	73.773%	73.773%	73.773%	73.773%
31	Intermediate Level Jurisdict. Capacity Charges	345,841	345,913	345,972	345,778	345,778	345,841	345,778	345,841	345,778	3,112,520
32	Sebring Base Rate Credits	(312,825)	(298,388)	(395,981)	(395,981)	(395,981)	(395,981)	(374,955)	(284,473)	(322,915)	(3,177,480)
33	Adjustment for Southern UPS Refund (jurisdictionalized)/Premiums				(2,715,091)	(576,214)	(819,400)	0	214,904	0	(3,895,801)
34	Jurisdictional Capacity Charges	25,030,663	24,602,712	24,565,927	21,615,987	23,893,699	23,531,406	24,450,629	24,666,567	24,231,181	216,588,771
35	Capacity Cost Recovery Revenues (net of tax)	19,502,310	19,858,612	26,257,039	27,825,317	28,470,534	26,496,376	25,482,570	20,742,899	20,496,855	215,132,512
36	Capacity Cost Revenues Adjustment (Net of Tax)										0
37	Prior Period True-Up Provision	282,567	282,567	282,567	282,567	282,567	282,567	1,848,305	1,949,305	1,949,305	7,543,315
38	Current Period Capacity Cost Recovery Revenues (net of tax) (sum of lines 35 through 37)	19,784,877	20,141,179	26,539,605	28,107,884	28,753,100	26,778,943	27,431,875	22,692,204	22,446,160	222,675,827
39	True-Up Provision - Over/(Under) Recovery (line 38 - line 34)	(5,245,786)	(4,461,533)	1,973,678	6,491,897	4,859,401	3,247,537	2,981,246	(1,974,363)	(1,785,021)	6,087,056
40	Interest Provision for the Month	(57,374)	(2,322)	(36,140)	(18,138)	6,928	23,639	31,372	26,004	9,008	(17,022)
41	Current Cycle Balance (line 39 + line 40) Cumulative	(5,303,161)	(9,767,016)	(7,829,478)	(1,355,719)	3,510,611	6,781,787	9,794,405	7,846,046	6,070,033	
42	True-Up & Interest Provision (beginning)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	(9,662,568)	
43	Prior Period True-Up Collected/(Refunded) Cumulative	(282,567)	10,845,274	10,562,708	10,229,536	9,946,969	9,662,568	7,713,263	5,763,958	3,814,653	
44	Other: Adjustment to Remove Orlando Settlement Payments	11,410,407		(50,605)	0	0	(1,834)	0	0	0	
45	End of Period Net True-Up (lines 41 through 44) Over / (Under)	($3,837,888)	($8,584,310)	($8,979,943)	($788,751)	$3,795,012	$6,779,954	$7,845,100	$3,947,436	$222,119	$0

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Description	1998 APRIL	1998 MAY	1998 JUNE	1998 JULY	1998 AUGUST	1998 SEPTEMBER	1998 OCTOBER	1998 NOVEMBER	1998 DECEMBER
Interest Provision:									
1. Beginning True-Up	($9,662,568)	($3,837,888)	($8,584,310)	($6,979,943)	($788,751)	$3,795,012	$6,779,954	$7,845,100	$3,947,436
2. Ending True-Up	($15,190,921)	$2,828,420	($6,893,198)	($821,219)	$3,788,083	$6,758,148	$7,811,894	$3,921,432	$213,111
3. Total True-Up (line 1 + line 2)	($24,853,489)	($1,009,469)	($15,477,507)	($7,801,162)	$2,999,332	$10,553,160	$14,591,848	$11,766,532	$4,160,547
4. Average True-Up (50% of line 3)	($12,426,744)	($504,734)	($7,738,754)	($3,900,581)	$1,499,666	$5,276,580	$7,295,924	$5,883,266	$2,080,273
5. Interest Rate - First Day of Reporting Month	5.550%	5.530%	5.600%	5.600%	5.560%	5.520%	5.220%	5.100%	5.500%
6. Interest Rate - First Day of Subsequent Month	5.530%	5.500%	5.600%	5.560%	5.520%	5.220%	5.100%	5.500%	4.900%
7. Total Interest (line 5 + line 6)	11.080%	11.030%	11.200%	11.160%	11.080%	10.740%	10.320%	10.600%	10.400%
8. Average Interest Rate (50% of line 7)	5.540%	5.515%	5.600%	5.580%	5.540%	5.370%	5.160%	5.300%	5.200%
9. Monthly Average Interest Rate (line 8 / 12)	0.4617%	0.460%	0.467%	0.465%	0.462%	0.448%	0.430%	0.442%	0.433%
10. Interest Provision (line 4 x line 9)	($57,374)	($2,322)	($36,140)	($18,138)	$6,928	$23,639	$31,372	$26,004	$9,008
11. Cumulative Interest for the Period Ending	($57,374)	($59,696)	($95,836)	($113,974)	($107,045)	($83,406)	($52,034)	($26,030)	($17,022)

Florida Power Corporation
Docket No. 990001-EI
Witness: McClintock
Exhibit No. _____ (RJM-1)

GPIF REWARD/PENALTY SCHEDULES

Descriptive Title	Sheet
• Reward/Penalty Table (Actual)	1
• Calculation of Maximum Incentive Dollars (Actual)	2
• Calculation of System Actual GPIF Points	3
• GPIF Unit Performance Summary	4
• Actual Unit Performance Data	5
• Adjustments to EAF Actual	6
• Adjustments to ANOHR Actual	7
• Generating Performance Incentive Points Table	8-14
• Actual Unit Performance Data	15-21
• Planned Outage Schedules (Actual)	22-24

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO 7
COMPANY/ WITNESS: M. McClintock
DATE: 11-22-99

Original Sheet No. 6.101.01

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

	Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
	10	$5,997,600	$3,555,791
	9	$5,397,840	$3,200,212
	8	$4,798,080	$2,844,633
	7	$4,198,320	$2,489,054
	6	$3,598,560	$2,133,475
	5	$2,998,800	$1,777,896
	4	$2,399,040	$1,422,317
	3	$1,799,280	$1,066,737
	2	$1,199,520	$711,158
	1	$599,760	$355,579
****	0.957	$573,970	$340,289
	0	$0	$0
	-1	($652,250)	($355,579)
	-2	($1,304,500)	($711,158)
	-3	($1,956,750)	($1,066,737)
	-4	($2,609,000)	($1,422,317)
	-5	($3,261,250)	($1,777,896)
	-6	($3,913,500)	($2,133,475)
	-7	($4,565,750)	($2,489,054)
	-8	($5,218,000)	($2,844,633)
	-9	($5,870,250)	($3,200,212)
	-10	($6,522,500)	($3,555,791)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

COMPANY: FLORIDA POWER CORPORATION
FOR THE PERIOD OF:
Period of: April, 1998 - September, 1998

1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY	$1,764,294,000
2	END OF MONTH BALANCE OF COMMON EQUITY: MONTH OF APRIL 1998	$1,777,378,000
3	MONTH OF MAY 1998	$1,800,127,000
4	MONTH OFJUNE 1998	$1,782,970,000
5	MONTH OF JULY 1998	$1,818,856,000
6	MONTH OF AUGUST 1998	$1,859,461,000
7	MONTH OF SEPTEMBER 1998	$1,842,833,000
8	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 7 DIVIDED BY 7)	$1,806,559,857
9	25 BASIS POINTS	0.0025
10	REVENUE EXPANSION FACTOR	61.3738%
11	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 8 TIMES LINE 9 DIVIDED BY LINE 10 TIMES 0.5)	$3,679,420
12	JURISDICTIONAL SALES	18,074,895 MWH
13	TOTAL SALES	18,703,561 MWH
14	JURISDICTIONAL SEPARATION FACTOR (LINE 12 DIVIDED BY LINE 13)	96.64%
15	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 11 TIMES LINE 14)	$3,555,791

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CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Crystal River 1	EAF	4.15	-10.000	-0.415
	ANOHR	3.13	0.000	0.000
Crystal River 2	EAF	15.51	-5.876	-0.911
	ANOHR	4.80	0.000	0.000
Crystal River 3	EAF	19.66	10.000	1.966
	ANOHR	8.03	0.000	0.000
Crystal River 4	EAF	8.95	10.000	0.895
	ANOHR	7.17	0.000	0.000
Crystal River 5	EAF	2.23	-3.460	-0.077
	ANOHR	9.78	-4.727	-0.462
Anclote 1	EAF	0.68	3.166	0.022
	ANOHR	7.30	-0.29	-0.021
Anclote 2	EAF	0.38	-10.000	-0.038
	ANOHR	8.25	0.000	0
GPIF System		100.00		0.959

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GPIF UNIT PERFORMANCE SUMMARY

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
CR 1	4.15	73.26	76.56	66.66	372.7	886.1	65.62	$886.1
CR 2	15.51	85.51	91.18	72.39	1394.3	781.9	77.80	$459.4
CR 3	19.66	92.85	96.21	86.00	1766.9	3821.1	97.83	$1,766.9
CR 4	8.95	80.53	83.25	74.99	804.1	1280.2	83.55	$804.1
CR 5	2.23	96.85	98.34	93.75	200.1	482.0	95.77	$166.8
AN 1	0.68	95.51	97.61	91.26	61.4	277.1	96.17	$19.4
AN 2	0.38	95.49	97.61	91.15	34.4	74.4	83.87	$74.4
GPIF System	51.55				4633.9	7,602.8		$4,177.2

Plant/Unit	Weighting Factor (%)	ANOHR Target (Btu/kwh)	NOF	ANOHR RANGE Min. Btu/kwh	Max. Btu/kwh	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual Btu/kwh	Estimated Fuel Savings/ Loss
CR 1	3.13	9805	90.7	9655	9955	281.6	(281.6)	9808.2	$0.0
CR 2	4.80	9773	94.4	9623	9923	431.3	(431.3)	9732.1	$0.0
CR 3	8.03	10463	99.0	10313	10613	722.0	(722.0)	10401.1	$0.0
CR 4	7.17	9438	84.9	9288	9588	644.3	(644.3)	9461.7	$0.0
CR 5	9.78	9344	97.5	9194	9494	878.8	(878.8)	9454.2	($415.4)
AN 1	7.30	9785	77.2	9554	10016	655.8	(655.8)	9864.53	($19.3)
AN 2	8.25	9846	72.2	9573	10120	741.6	(741.6)	9892.02	$0.0
GPIF System	48.45					4355.4	(4,355.4)		($434.7)

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ACTUAL UNIT PERFORMANCE DATA

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

PLANT/UNIT	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	EAF ADJUSTED ACTUAL %
CRYSTAL RIVER 1	69.15	-3.53	65.62
CRYSTAL RIVER 2	79.65	-1.85	77.80
CRYSTAL RIVER 3	97.84	-0.00	97.84
CRYSTAL RIVER 4	85.70	-2.15	83.55
CRYSTAL RIVER 5	95.80	0.00	95.80
ANCLOTE UNIT 1	96.19	-0.00	96.19
ANCLOTE UNIT 2	83.95	-0.00	83.95

PLANT/UNIT	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ANOHR ADJUSTED ACTUAL BTU/KWH
CRYSTAL RIVER 1	9879.8	-71.7	9808.2
CRYSTAL RIVER 2	9758.3	-26.2	9732.1
CRYSTAL RIVER 3	10329.0	72.1	10401.1
CRYSTAL RIVER 4	9412.1	49.6	9461.7
CRYSTAL RIVER 5	9473.6	-19.4	9454.2
ANCLOTE UNIT 1	9984.3	-119.8	9864.5
ANCLOTE UNIT 2	9982.4	-90.40	9892.0

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.
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Original Sheet No. 6.101.06

ADJUSTMENTS TO EAF ACTUAL

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

EAF ADJUSTMENTS FOR PLANNED OUTAGE HOURS		CR1	CR2	CR3	CR4	CR5	AN1	AN2
1. ACTUAL POH	HRS.	684.00	0.00	0.00	506.32	0.00	0.00	0.00
2. TARGET POH	HRS.	864.00	96.00	0.00	600.00	0.00	0.00	0.00
3. ADJ. FACTOR (PH-POHT/PH-POHA)		0.95	0.98	1.00	0.98	1.00	1.00	1.00
4. ACTUAL EUOH *	HRS.	670.80	893.47	94.84	121.69	184.63	167.22	704.62
5. ADJ. EUOH (3*4)	HRS.	638.03	873.84	94.84	118.74	184.63	167.22	704.62
6. ACTUAL EAF *	%	69.15	79.65	97.84	85.70	95.80	96.19	83.95
7. ADJUSTED EAF (using 2 & 5)	%	65.62	77.80	97.84	83.55	95.80	96.19	83.95
8. DIFFERENCE	%	-3.53	-1.85	-0.00	-2.15	0.00	-0.00	-0.00
9. TOTAL ADJ TO EAF (6 • 8)	%	-3.53	-1.85	-0.00	-2.15	0.00	-0.00	-0.00

*Actual EUOH and actual EAF are the adjusted values in Nos. 3 and 5 above.

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ADJUSTMENTS TO ANOHR ACTUAL

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998

		CR 1	CR 2	CR 3	CR 4	CR 5	AN 1	AN 2
ANOHR adj for Target NOF								
1. Target NOF	%	90.7	94.4	99.0	84.9	97.5	77.2	72.2
2. Target ANOH R	Btu/kwh	9804.5	9773.4	10463.4	9438.4	9343.7	9785.0	9846.5
3. Actual NOF	%	85.0	89.8	101.4	95.1	91.4	62.5	63.4
4. Calc. ANOHR (using 3)	Btu/kwh	9876.2	9799.6	10391.2	9388.8	9363.1	9904.8	9936.9
5. Total adj. to ANOHR (2-4)	Btu/kwh	-71.7	-26.2	72.2	49.6	-19.4	-119.8	-90.4

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Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Crystal River 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$372,700	76.56	10	$281,600	9654.5	
	9	$335,430	76.23	9	$253,440	9662.0	
	8	$298,160	75.90	8	$225,280	9669.5	
	7	$260,890	75.57	7	$197,120	9677.0	
	6	$223,620	75.24	6	$168,960	9684.5	
	5	$186,350	74.91	5	$140,800	9692.0	
	4	$149,080	74.58	4	$112,640	9699.5	
	3	$111,810	74.25	3	$84,480	9707.0	
	2	$74,540	73.92	2	$56,320	9714.5	
	1	$37,270	73.59	1	$28,160	9722.0	
		$0	73.26	0	$0	9729.5	
	0	$0	73.26	0.000	$0	9808.2	****
		$0	73.26	0	$0	9804.5	
	-1	($88,610)	72.60	0	$0	9879.5	
	-2	($177,220)	71.94	-1	($28,160)	9887.0	
	-3	($265,830)	71.28	-2	($56,320)	9894.5	
	-4	($354,440)	70.62	-3	($84,480)	9902.0	
	-5	($443,050)	69.96	-4	($112,640)	9909.5	
	-6	($531,660)	69.30	-5	($140,800)	9917.0	
	-7	($620,270)	68.64	-6	($168,960)	9924.5	
	-8	($708,880)	67.98	-7	($197,120)	9932.0	
	-9	($797,490)	67.32	-8	($225,280)	9939.5	
	-10	($886,100)	66.66	-9	($253,440)	9947.0	
****	-10.000	($886,100)	65.62	-10	($281,600)	9954.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.15%	3.13%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Crystal River 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,394,300	91.18	10	$431,300	9623.4	
	9	$1,254,870	90.61	9	$388,170	9630.9	
	8	$1,115,440	90.05	8	$345,040	9638.4	
	7	$976,010	89.48	7	$301,910	9645.9	
	6	$836,580	88.91	6	$258,780	9653.4	
	5	$697,150	88.35	5	$215,650	9660.9	
	4	$557,720	87.78	4	$172,520	9668.4	
	3	$418,290	87.21	3	$129,390	9675.9	
	2	$278,860	86.65	2	$86,260	9683.4	
	1	$139,430	86.08	1	$43,130	9690.9	
		$0	85.51	0	$0	9698.4	
	0	$0	85.51	0.000	$0	9732.1	****
		$0	85.51	0	$0	9773.4	
	-1	($78,190)	84.20	0	$0	9848.4	
	-2	($156,380)	82.89	-1	($43,130)	9855.9	
	-3	($234,570)	81.58	-2	($86,260)	9863.4	
	-4	($312,760)	80.26	-3	($129,390)	9870.9	
	-5	($390,950)	78.95	-4	($172,520)	9878.4	
****	-5.876	($459,432)	77.80	-5	($215,650)	9885.9	
	-6	($469,140)	77.64	-6	($258,780)	9893.4	
	-7	($547,330)	76.33	-7	($301,910)	9900.9	
	-8	($625,520)	75.01	-8	($345,040)	9908.4	
	-9	($703,710)	73.70	-9	($388,170)	9915.9	
	-10	($781,900)	72.39	-10	($431,300)	9923.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
15.51%	4.80%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Crystal River 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$1,766,900	97.84	10	$722,000	10313.4	
	10	$1,766,900	96.21	9	$649,800	10320.9	
	9	$1,590,210	95.87	8	$577,600	10328.4	
	8	$1,413,520	95.54	7	$505,400	10335.9	
	7	$1,236,830	95.20	6	$433,200	10343.4	
	6	$1,060,140	94.87	5	$361,000	10350.9	
	5	$883,450	94.53	4	$288,800	10358.4	
	4	$706,760	94.20	3	$216,600	10365.9	
	3	$530,070	93.86	2	$144,400	10373.4	
	2	$353,380	93.52	1	$72,200	10380.9	
	1	$176,690	93.19	0	$0	10388.4	
		$0	92.85	0.000	$0	10401.1	****
	0	$0	92.85	0	$0	10463.4	
		$0	92.85	0	$0	10538.4	
	-1	($382,110)	92.17	-1	($72,200)	10545.9	
	-2	($764,220)	91.48	-2	($144,400)	10553.4	
	-3	($1,146,330)	90.80	-3	($216,600)	10560.9	
	-4	($1,528,440)	90.11	-4	($288,800)	10568.4	
	-5	($1,910,550)	89.43	-5	($361,000)	10575.9	
	-6	($2,292,660)	88.74	-6	($433,200)	10583.4	
	-7	($2,674,770)	88.06	-7	($505,400)	10590.9	
	-8	($3,056,880)	87.37	-8	($577,600)	10598.4	
	-9	($3,438,990)	86.69	-9	($649,800)	10605.9	
	-10	($3,821,100)	86.00	-10	($722,000)	10613.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
19.66%	8.03%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$804,100	83.55	10	$644,300	9288.4	
	10	$804,100	83.25	9	$579,870	9295.9	
	9	$723,690	82.98	8	$515,440	9303.4	
	8	$643,280	82.71	7	$451,010	9310.9	
	7	$562,870	82.43	6	$386,580	9318.4	
	6	$482,460	82.16	5	$322,150	9325.9	
	5	$402,050	81.89	4	$257,720	9333.4	
	4	$321,640	81.62	3	$193,290	9340.9	
	3	$241,230	81.34	2	$128,860	9348.4	
	2	$160,820	81.07	1	$64,430	9355.9	
	1	$80,410	80.80	0	$0	9363.4	
		$0	80.53	0	$0	9438.4	
	0	$0	80.53	0.000	$0	9461.7	****
		$0	80.53	0	$0	9513.4	
	-1	($128,020)	79.97	-1	($64,430)	9520.9	
	-2	($256,040)	79.42	-2	($128,860)	9528.4	
	-3	($384,060)	78.87	-3	($193,290)	9535.9	
	-4	($512,080)	78.31	-4	($257,720)	9543.4	
	-5	($640,100)	77.76	-5	($322,150)	9550.9	
	-6	($768,120)	77.21	-6	($386,580)	9558.4	
	-7	($896,140)	76.65	-7	($451,010)	9565.9	
	-8	($1,024,160)	76.10	-8	($515,440)	9573.4	
	-9	($1,152,180)	75.55	-9	($579,870)	9580.9	
	-10	($1,280,200)	74.99	-10	($644,300)	9588.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.95%	7.17%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
		0.00					
	10	$200,100	98.34	10	$878,800	9193.7	
	9	$180,090	98.19	9	$790,920	9201.2	
	8	$160,080	98.04	8	$703,040	9208.7	
	7	$140,070	97.89	7	$615,160	9216.2	
	6	$120,060	97.74	6	$527,280	9223.7	
	5	$100,050	97.59	5	$439,400	9231.2	
	4	$80,040	97.44	4	$351,520	9238.7	
	3	$60,030	97.29	3	$263,640	9246.2	
	2	$40,020	97.14	2	$175,760	9253.7	
	1	$20,010	96.99	1	$87,880	9261.2	
		$0	96.85	0	$0	9268.7	
	0	$0	96.85	0	$0	9343.7	
		$0	96.85	0	$0	9418.7	
	-1	($48,200)	96.54	-1	($87,880)	9426.2	
	-2	($96,400)	96.23	-2	($175,760)	9433.7	
	-3	($144,600)	95.92	-3	($263,640)	9441.2	
****	-3.460	($166,781)	95.80	-4	($351,520)	9448.7	
	-4	($192,800)	95.61	-4.727	($415,421)	9454.2	****
	-5	($241,000)	95.30	-5	($439,400)	9456.2	
	-6	($289,200)	94.99	-6	($527,280)	9463.7	
	-7	($337,400)	94.68	-7	($615,160)	9471.2	
	-8	($385,600)	94.37	-8	($703,040)	9478.7	
	-9	($433,800)	94.06	-9	($790,920)	9486.2	
	-10	($482,000)	93.75	-10	($878,800)	9493.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.23%	9.78%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: *Anclote 1*

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$61,400	97.61	10	$655,800	9554.0	
	9	$55,260	97.40	9	$590,220	9569.6	
	8	$49,120	97.19	8	$524,640	9585.2	
	7	$42,980	96.98	7	$459,060	9600.8	
	6	$36,840	96.77	6	$393,480	9616.4	
	5	$30,700	96.56	5	$327,900	9632.0	
	4	$24,560	96.35	4	$262,320	9647.6	
****	3.166	$19,439	96.19	3	$196,740	9663.2	
	3	$18,420	96.14	2	$131,160	9678.8	
	2	$12,280	95.93	1	$65,580	9694.4	
	1	$6,140	95.72	0	$0	9710.0	
	0	$0	95.51	0	$0	9785.0	
	0	$0	95.51	0	$0	9860.0	
	0	$0	95.51	-0.294	($19,265)	9864.5	****
	-1	($27,710)	95.08	-1	($65,580)	9875.6	
	-2	($55,420)	94.66	-2	($131,160)	9891.2	
	-3	($83,130)	94.23	-3	($196,740)	9906.8	
	-4	($110,840)	93.81	-4	($262,320)	9922.4	
	-5	($138,550)	93.38	-5	($327,900)	9938.0	
	-6	($166,260)	92.96	-6	($393,480)	9953.6	
	-7	($193,970)	92.53	-7	($459,060)	9969.2	
	-8	($221,680)	92.11	-8	($524,640)	9984.8	
	-9	($249,390)	91.68	-9	($590,220)	10000.4	
	-10	($277,100)	91.26	-10	($655,800)	10016.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.68%	7.30%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: April, 1998 - September, 1998
Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$34,400	97.61	10	$741,600	9572.7	
	9	$30,960	97.40	9	$667,440	9592.6	
	8	$27,520	97.19	8	$593,280	9612.5	
	7	$24,080	96.98	7	$519,120	9632.3	
	6	$20,640	96.76	6	$444,960	9652.2	
	5	$17,200	96.55	5	$370,800	9672.1	
	4	$13,760	96.34	4	$296,640	9692.0	
	3	$10,320	96.13	3	$222,480	9711.9	
	2	$6,880	95.92	2	$148,320	9731.7	
	1	$3,440	95.70	1	$74,160	9751.6	
	0	$0	95.49	0	$0	9771.5	
		0.00	95.49	0	$0	9846.5	
		$0	95.49	0.000	$0	9892.0	****
	-1	($7,440)	95.06	0	$0	9921.5	
	-2	($14,880)	94.62	-1	($74,160)	9941.4	
	-3	($22,320)	94.19	-2	($148,320)	9961.3	
	-4	($29,760)	93.76	-3	($222,480)	9981.1	
	-5	($37,200)	93.32	-4	($296,640)	10001.0	
	-6	($44,640)	92.89	-5	($370,800)	10020.9	
	-7	($52,080)	92.45	-6	($444,960)	10040.8	
	-8	($59,520)	92.02	-7	($519,120)	10060.7	
	-9	($66,960)	91.58	-8	($593,280)	10080.5	
	-10	($74,400)	91.15	-9	($667,440)	10100.4	
****	-10.000	($74,400)	83.95	-10	($741,600)	10120.3	

Equivalent Availability *Weighting Factor*:	Heat Rate Weighting Factor:
0.38%	8.25%

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 1	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	63.15	42.84	70.57	50.14	93.47	95.40	69.15
2. PH	719	744	720	744	744	720	4391
3. SH	457.0	320.3	582.0	386.9	712.5	720.0	3178.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	262.0	423.8	138.0	357.1	31.5	0.0	1212.2
6. POH	262.0	422.0	0.0	0.0	0.0	0.0	684.0
7. FOH	0.0	1.7	0.0	162.3	31.5	0.0	195.4
8. MOH	0.0	0.0	138.0	194.8	0.0	0.0	332.8
9. PFOH	4.3	3.0	273.6	138.6	46.6	49.5	515.6
10. LR PF (MW)	40.5	186.0	97.3	37.4	108.1	121.2	84.5
11. PMOH	5.0	0.0	13.1	0.0	8.6	46.2	72.9
12. LR PM (MW)	186.0	0.0	66.6	0.0	155.7	137.0	129.9
13. NSC (MW)	372	372	372	372	372	372	372
14. OPER MBTU	1565383	994596	1776007	1066894	2352592	2175411	9930883
15. NET GEN (MWH)	159696	102038	177520	106095	237204	222615	1005168
16. ANOHR (BTU/KWH)	9802.3	9747.3	10004.5	10056.0	9918.0	9772.1	9879.8
17. NOF (%)	93.9	85.7	82.0	73.7	89.5	83.1	85.0
18. NPC (MW)	372	372	372	372	372	372	372

ANOHR EQUATION: ANOHR = -12.475 * NOF + 10936.6

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 2	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	94.16	68.22	21.80	98.85	99.38	94.60	79.65
2. PH	719	744	720	744	744	720	4391
3. SH	693.5	530.0	157.0	744.0	744.0	718.8	3587.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	25.5	214.1	563.0	0.0	0.0	1.2	803.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	1.2	214.1	534.6	0.0	0.0	1.2	751.0
8. MOH	24.3	0.0	28.5	0.0	0.0	0.0	52.8
9. PFOH	251.8	494.8	0.0	16.6	107.3	56.9	927.4
10. LR PF (MW)	6.9	13.7	0.0	29.5	20.0	120.5	19.4
11. PMOH	28.9	16.0	0.0	37.4	0.0	49.3	131.5
12. LR PM (MW)	206.9	234.0	0.0	93.6	0.0	219.0	182.5
13. NSC (MW)	468	468	468	468	468	468	468
14. OPER MBTU	2536873	1988510	629581	3324316	3348329	2885980	14713589
15. NET GEN (MWH)	261665	202759	63207	341576	341346	297255	1507808
16. ANOHR (BTU/KWH)	9695.1	9807.3	9960.6	9732.3	9809.2	9708.8	9758.3
17. NOF (%)	80.6	81.8	86.0	98.1	98.0	88.4	89.8
18. NPC (MW)	468	468	468	468	468	468	468

ANOHR EQUATION: ANOHR = -5.706 * NOF + 10312.0

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 3	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	95.50	99.51	99.99	98.26	93.83	100.00	97.84
2. PH	719	744	720	744	744	720	4391
3. SH	706.3	744.0	720.0	744.0	704.5	720.0	4338.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	12.7	0.0	0.0	0.0	39.5	0.0	52.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	39.5	0.0	39.5
8. MOH	12.7	0.0	0.0	0.0	0.0	0.0	12.7
9. PFOH	0.0	30.2	0.0	79.6	0.0	0.0	109.8
10. LR PF (MW)	0.0	89.2	0.0	19.5	0.0	0.0	38.7
11. PMOH	72.4	0.0	3.0	71.2	20.9	0.0	167.5
12. LR PM (MW)	201.6	0.0	9.1	113.4	227.9	0.0	163.9
13. NSC (MW)	743	743	743	743	743	743	743
14. OPER MBTU	5439981	5811561	5648432	5733544	5491964	5650215	33775697
15. NET GEN (MWH)	529717	567837	544744	551012	527085	549601	3269996
16. ANOHR (BTU/KWH)	10269.6	10234.6	10369.0	10405.5	10419.5	10280.6	10329.0
17. NOF (%)	100.9	102.7	101.8	99.7	100.7	102.7	101.4
18. NPC (MW)	743	743	743	743	743	743	743

ANOHR EQUATION: ANOHR = -29.749 * NOF + 13408.8

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Original Sheet No. 6.101.18

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 4	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	27.36	89.98	98.30	98.77	98.83	99.85	85.70
2. PH	719	744	720	744	744	720	4391
3. SH	196.7	669.8	720.0	744.0	737.7	720.0	3788.3
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	522.3	74.2	0.0	0.0	6.3	0.0	602.8
6. POH	506.3	0.0	0.0	0.0	0.0	0.0	506.3
7. FOH	0.0	0.0	0.0	0.0	6.3	0.0	6.3
8. MOH	16.0	74.2	0.0	0.0	0.0	0.0	-90.2
9. PFOH	0.0	0.4	50.7	26.8	16.7	21.6	116.1
10. LR PF (MW)	0.0	697.0	168.8	238.7	100.1	34.8	151.7
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	697	697	697	697	697	697	697
14. OPER MBTU	1043083	3991304	4638661	4790710	4769447	4405600	23638805
15. NET GEN (MWH)	108000	428877	495686	510424	503919	464640	2511546
16. ANOHR (BTU/KWH)	9658.2	9306.4	9358.1	9385.7	9464.7	9481.7	9412.1
17. NOF (%)	78.8	91.9	98.8	98.4	98.0	92.6	95.1
18. NPC (MW)	697.0	697.0	697.0	697.0	697.0	697.0	697

ANOHR EQUATION: ANOHR = -4.847 * NOF + 9849.9

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 5	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	95.69	98.82	88.45	97.37	98.86	95.32	95.80
2. PH	719	744	720	744	744	720	4391
3. SH	705.6	744.0	641.3	737.7	744.0	688.8	4261.4
4. RSH	11.5	0.0	0.0	0.0	0.0	0.0	11.5
5. UH	1.9	0.0	78.7	6.3	0.0	31.2	118.1
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	1.9	0.0	78.7	6.3	0.0	31.2	118.1
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	45.2	2.2	56.3	32.5	12.6	17.2	166.1
10. LR PF (MW)	449.1	124.0	55.2	284.2	467.5	100.0	244.1
11. PMOH	0.0	122.3	0.0	0.0	0.0	0.0	122.3
12. LR PM (MW)	0.0	47.7	0.0	0.0	0.0	0.0	47.7
13. NSC (MW)	697	697	697	697	697	697	697
14. OPER MBTU	3961393	4332471	4075699	4611484	4695781	4038297	25715125
15. NET GEN (MWH)	413393.0	460044.0	430279.0	486309.0	494835.0	429551.0	2714411.0
16. ANOHR (BTU/KWH)	9582.6	9417.5	9472.2	9482.6	9489.6	9401.2	9473.6
17. NOF (%)	84.1	88.7	96.3	94.6	95.4	89.5	91.4
18. NPC (MW)	697	697	697	697	697	697	697

ANOHR EQUATION: ANOHR = -3.168 * NOF + 9652.6

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 1	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	97.19	97.37	96.82	91.20	96.86	97.82	96.19
2. PH	719	744	720	744	744	720	4391
3. SH	719.0	743.2	720.0	703.3	744.0	720.0	4349.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.8	0.0	40.7	0.0	0.0	41.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.8	0.0	40.7	0.0	0.0	41.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	9.4	9.1	20.0	187.1	3.3	0.0	228.9
10. LR PF (MW)	227.8	66.4	249.8	18.0	156.9	0.0	50.8
11. PMOH	48.3	53.0	40.7	96.9	76.6	48.5	364.0
12. LR PM (MW)	169.7	169.7	164.2	95.8	149.3	165.5	144.5
13. NSC (MW)	511	511	511	511	511	511	511
14. OPER MBTU	1935485	2256191	2556070	2466623	2454750	2208722	13877841
15. NET GEN (MWH)	194328	223006	258666	246395	251547	216018	1389960
16. ANOHR (BTU/KWH)	9959.9	10117.2	9881.7	10010.8	9758.6	10224.7	9984.3
17. NOF (%)	52.9	58.7	70.3	68.6	66.2	58.7	62.5
18. NPC (MW)	511.0	511.0	511.0	511.0	511.0	511.0	511

ANOHR EQUATION: ANOHR = -8.144 * NOF + 10414.1

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ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 2	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Apr-Sept Period
1. EAF	33.31	96.66	89.08	96.63	88.89	98.06	83.95
2. PH	719	744	720	744	744	720	4391
3. SH	265.5	744.0	690.2	744.0	689.3	720.0	3852.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	453.6	0.0	29.8	0.0	54.7	0.0	538.1
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	6.7	0.0	29.8	0.0	48.3	0.0	84.8
8. MOH	446.8	0.0	0.0	0.0	6.5	0.0	453.3
9. PFOH	102.3	25.2	199.9	24.1	24.4	0.0	375.9
10. LR PF (MW)	96.1	21.3	82.3	51.1	44.6	0.0	77.5
11. PMOH	26.3	61.7	51.2	70.3	80.1	43.0	332.7
12. LR PM (MW)	130.3	196.7	165.4	164.9	164.8	165.8	168.3
13. NSC (MW)	511	511	511	511	511	511	511
14. OPER MBTU	758203	2252711	2389057	2560386	2397031	2101776	12459164
15. NET GEN (MWH)	75734	227901	241190	258376	234363	210547	1248111
16. ANOHR (BTU/KWH)	10011.4	9884.6	9905.3	9909.5	10227.9	9982.5	9982.4
17. NOF (%)	55.8	59.9	68.4	68.0	66.5	57.2	63.4
18. NPC (MW)	511.0	511.0	511.0	511.0	511.0	511.0	511

ANOHR EQUATION: ANOHR = -10.213 * NOF + 10584.3

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PLANNED OUTAGE SCHEDULES
ACTUAL

Company: Florida Power Corporation
Period of: April 1998 - September 1998

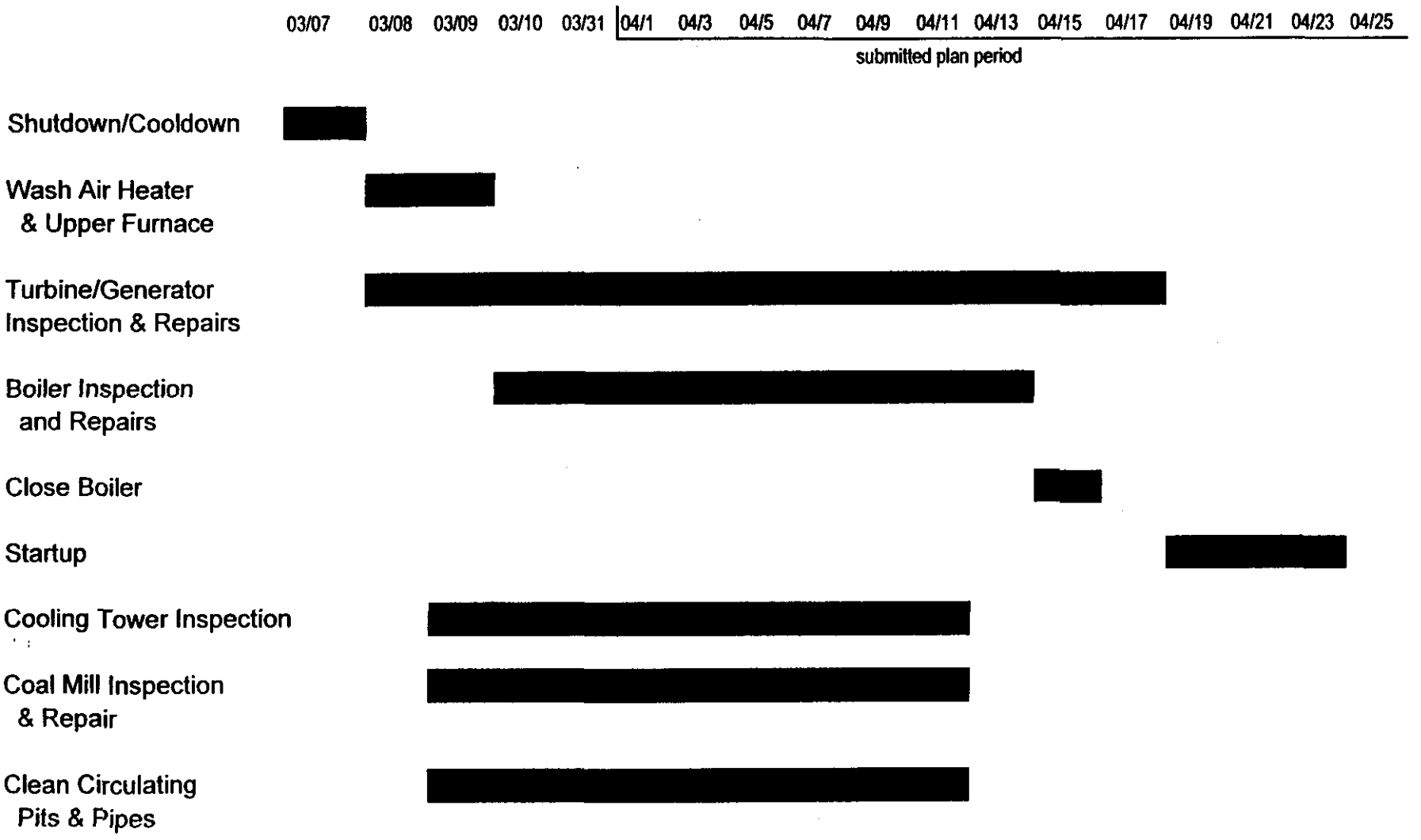
Plant/Unit	Actual Outage Dates	Reason for Outage(1)
Crystal River 1	04/20(0001) - 05/18(2400)	Boiler Inspection
Crystal River 4	03/07(0001) - 04/22(2400)	Turbine/Generator/Boiler

(1) To be accompanied by a critical path bar chart or milestone date chart of major activity to be performed during the outage.

FLORIDA POWER CORPORATION

ACTUAL FOR CRYSTAL RIVER #4 1998 TURBINE/GENERATOR/BOILER

(indicating dates ending midnight)



= (DENOTES CRITICAL PATH)

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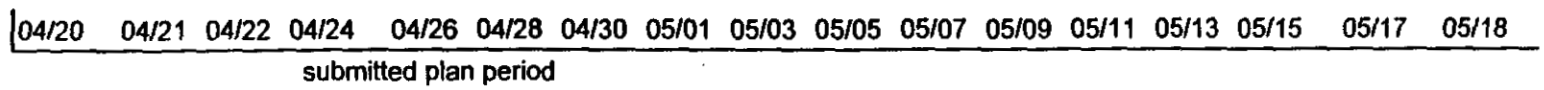
FLORIDA POWER CORPORATION

ACTUAL FOR CRYSTAL RIVER #1 1998 BOILER INSPECTION

(indicating dates ending midnight)



Shutdown/Cooldown

Wash Air Heater & Upper Furnace

Turbine/Generator Inspection

Boiler Inspection

Close Boiler

Startup

=(DENOTES CRITICAL PATH)

GPI98CR1.XLS

Florida Power Corporation
Docket No. 990001-EI
Witness: McClintock
Exhibit No. _____ (RJM-1)

GPIF REWARD/PENALTY SCHEDULES

Descriptive Title	Sheet
• Reward/Penalty Table (Actual)	1
• Calculation of Maximum Incentive Dollars (Actual)	2
• Calculation of System Actual GPIF Points	3
• GPIF Unit Performance Summary	4
• Actual Unit Performance Data	5
• Adjustments to EAF Actual	6
• Adjustments to ANOHR Actual	7
• Generating Performance Incentive Points Table	8-14
• Actual Unit Performance Data	15-21
• Planned Outage Schedules (Actual)	22-24

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 8
COMPANY/
WITNESS: McClintock
DATE 12-22-99

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Company: Florida Power Corporation
Period of: October 1998 - December 1998

	Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
	10	$5,997,600	$1,823,945
	9	$5,397,840	$1,641,551
	8	$4,798,080	$1,459,156
	7	$4,198,320	$1,276,762
	6	$3,598,560	$1,094,367
	5	$2,998,800	$911,973
	4	$2,399,040	$729,578
****	3.875	$2,324,308	$706,851
	3	$1,799,280	$547,184
	2	$1,199,520	$364,789
	1	$599,760	$182,395
	0	$0	$0
	-1	$652,250	($182,395)
	-2	$1,304,500	($364,789)
	-3	$1,956,750	($547,184)
	-4	$2,609,000	($729,578)
	-5	$3,261,250	($911,973)
	-6	$3,913,500	($1,094,367)
	-7	$4,565,750	($1,276,762)
	-8	$5,218,000	($1,459,156)
	-9	$5,870,250	($1,641,551)
	-10	($6,522,500)	($1,823,945)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

COMPANY: FLORIDA POWER CORPORATION
FOR THE PERIOD OF:
October 1998 - December 1998

1	Beginning of period balance of common equity	$1,842,833,000
2	END OF MONTH BALANCE OF COMMON EQUITY: Month of OCTOBER 1998	$1,863,964,766
3	Month of NOVEMBER 1998	$1,876,552,811
4	Month of DECEMBER 1998	$1,820,097,695
5	Average common equity for the period (Summation of LINE 1 through LINE 4 divided by 4)	$1,850,862,068
6	25 Basis Points	0.0025
7	Revenue Expansion Factor	61.3738%
8	Maximum allowed incentive dollars (LINE 5 times LINE 6 divided by LINE 7 times 0.25)	$1,884,825
9	Jurisdictional Sales *	8,390,433 MWH
10	Total Sales *	8,670,704 MWH
11	Jurisdictional Separation Factor (LINE 9 divided by LINE 10)	96.77%
12	Maximum allowed jurisdictional incentive dollars (LINE 8 times LINE 11)	$1,823,945

Net sales (Sales - Interruptible)

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CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Company: Florida Power Corporation
Period of: Oct. 1998 - Dec. 1998

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Anclote 1	EAF	0.84	7.115	0.060
	ANOHR	4.40	0.000	0.000
Anclote 2	EAF	0.23	10.000	0.023
	ANOHR	2.38	-0.431	-0.010
Crystal River 1	EAF	3.00	-5.192	-0.156
	ANOHR	5.96	0.000	0.000
Crystal River 2	EAF	5.56	8.549	0.475
	ANOHR	6.31	4.080	0.257
Crystal River 3	EAF	34.77	10.000	3.477
	ANOHR	10.00	4.721	0.472
Crystal River 4	EAF	4.17	-9.389	-0.392
	ANOHR	8.91	-0.715	-0.064
Crystal River 5	EAF	2.68	-10.000	-0.268
	ANOHR	10.80	0.000	0.000
GPIF System		100.00		3.875

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GPIF UNIT PERFORMANCE SUMMARY

Company: Florida Power Corporation
Period of: October 1998 - December 1998

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
ANC. 1	0.84	88.77	90.47	85.32	30.1	(52.6)	89.97	$21.4
ANC. 2	0.23	45.07	45.87	43.44	8.2	(21.9)	45.94	$8.2
C.R. 1	3.00	91.74	95.60	83.98	107.5	(25.1)	87.71	($13.0)
C.R. 2	5.56	89.50	94.36	77.62	199.5	(185.3)	93.66	$170.6
C.R. 3	34.77	90.71	95.06	81.91	1247.3	(2413.1)	98.44	$1,247.3
C.R. 4	4.17	91.89	95.68	84.30	149.7	(390.3)	84.76	($366.5)
C.R. 5	2.68	89.60	90.92	86.85	96.1	(127.3)	77.79	($127.3)
GPIF System	51.25				1838.4	(3215.6)		$940.7

Plant/Unit	Weighting Factor (%)	ANOHR Target (Btu/kwh)	NOF	ANOHR RANGE Max. (Btu/kwh)	ANOHR RANGE Min. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
ANC. 1	4.4	10192	40	9904	10479	157.9	(157.9)	10199.8	$0.0
ANC. 2	2.38	10284	32.7	9955	10613	85.5	(85.5)	10370.0	($3.7)
C.R. 1	5.96	9625	91.3	9445	9805	213.8	(213.8)	9597.5	$0.0
C.R. 2	6.31	9657	94.2	9507	9807	226.3	(226.3)	9551.4	$92.3
C.R. 3	10	10427	98.8	10277	10577	358.7	(358.7)	10316.6	$169.3
C.R. 4	8.91	9460	72.9	9310	9610	319.5	(319.5)	9540.4	($22.8)
C.R. 5	10.8	9301	92.6	9151	9451	387.4	(387.4)	9361.3	$0.0
GPIF System	48.76					1749.1	(1749.1)		$235.1

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ACTUAL UNIT PERFORMANCE DATA

Company: Florida Power Corporation
Period of: October 1998 - December 1998

PLANT/UNIT	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	EAF ADJUSTED ACTUAL %
CRYSTAL RIVER 1	87.71	0.00	87.71
CRYSTAL RIVER 2	93.66	0.00	93.66
CRYSTAL RIVER 3	98.44	0.00	98.44
CRYSTAL RIVER 4	84.76	0.00	84.76
CRYSTAL RIVER 5	84.21	-6.42	77.79
ANCLOTE UNIT 1	82.29	7.68	89.97
ANCLOTE UNIT 2	43.93	2.01	45.94

PLANT/UNIT	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ANOHR ADJUSTED ACTUAL BTU/KWH
CRYSTAL RIVER 1	9772.8	-175.3	9597.5
CRYSTAL RIVER 2	9767.9	-216.5	9551.4
CRYSTAL RIVER 3	10188.8	127.8	10316.6
CRYSTAL RIVER 4	9483.6	56.8	9540.4
CRYSTAL RIVER 5	9413.4	-52.1	9361.3
ANCLOTE UNIT 1	9734.0	465.8	10199.8
ANCLOTE UNIT 2	9705.6	664.4	10370.0

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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ADJUSTMENTS TO EAF ACTUAL

Company: Florida Power Corporation
Period of: October 1998 - December 1998

EAF ADJUSTMENTS FOR PLANNED OUTAGE HOURS		CR1	CR2	CR3	CR4	CR5	AN1	AN2
1. ACTUAL POH	HRS.	0.00	0.00	0.00	0.00	0.00	342.45	1221.63
2. TARGET POH	HRS.	0.00	0.00	0.00	0.00	168.00	168.00	1176.00
3. ADJ. FACTOR (PH-POHT/PH-POHA)		1.00	1.00	1.00	1.00	0.92	1.09	1.05
4. ACTUAL EUOH *	HRS.	271.47	140.16	34.56	336.58	348.88	48.79	16.91
5. ADJ. EUOH (3*4)	HRS.	271.47	140.16	34.56	336.58	322.33	53.36	17.69
6. ACTUAL EAF *	%	87.71	93.66	98.44	84.76	84.21	82.29	43.93
7. ADJUSTED EAF (using 2 & 5)	%	87.71	93.66	98.44	84.76	77.79	89.97	45.94
8. DIFFERENCE	%	0.00	0.00	0.00	0.00	-6.42	7.68	2.01
9. TOTAL ADJ TO EAF (6 + 8)	%	0.00	0.00	0.00	0.00	-6.42	7.68	2.01

* Actual EUOH and actual EAF are the adjusted values in Nos. 3 and 5 above.

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Docket No.:
Order No.:

ADJUSTMENTS TO ANOHR ACTUAL

Company: Florida Power Corporation
Period of: October 1998 - December 1998

ANOHR adj for Target NOF		CR 1	CR 2	CR 3	CR 4	CR 5	AN 1	AN 2
1. Target NOF	%	91.3	94.2	98.8	72.9	92.6	40.0	32.7
2. Target ANOHR	Btu/kwh	9625.0	9657.0	10427.0	9460.0	9301.0	10192.0	10284.0
3. Actual NOF	%	80.4	70.8	103.4	80.8	79.4	66.4	69.7
4. Calc. ANOHR (using 3)	Btu/kwh	9800.3	9873.5	10299.2	9403.2	9353.1	9726.2	9619.6
5. Total adj. to ANOHR (2-4)	Btu/kwh	-175.3	-216.5	127.8	56.8	-52.1	465.8	664.4

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Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Crystal River Unit 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$107,500	95.60	10	$213,800	9445.1	
	9	$96,750	95.21	9	$192,420	9455.6	
	8	$86,000	94.83	8	$171,040	9466.1	
	7	$75,250	94.44	7	$149,660	9476.6	
	6	$64,500	94.05	6	$128,280	9487.1	
	5	$53,750	93.67	5	$106,900	9497.6	
	4	$43,000	93.28	4	$85,520	9508.1	
	3	$32,250	92.90	3	$64,140	9518.6	
	2	$21,500	92.51	2	$42,760	9529.1	
	1	$10,750	92.12	1	$21,380	9539.6	
		$0	91.74	0	$0	9550.1	
	0	$0	91.74	0.000	$0	9597.5	****
		$0	91.74	0	$0	9625.1	
	-1	($2,510)	90.96	0	$0	9700.1	
	-2	($5,020)	90.19	-1	($21,380)	9710.6	
	-3	($7,530)	89.41	-2	($42,760)	9721.0	
	-4	($10,040)	88.63	-3	($64,140)	9731.5	
	-5	($12,550)	87.86	-4	($85,520)	9742.0	
****	-5.192	($13,032)	87.71	-5	($106,900)	9752.5	
	-6	($15,060)	87.08	-6	($128,280)	9763.0	
	-7	($17,570)	86.31	-7	($149,660)	9773.5	
	-8	($20,080)	85.53	-8	($171,040)	9784.0	
	-9	($22,590)	84.75	-9	($192,420)	9794.5	
	-10	($25,100)	83.98	-10	($213,800)	9805.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.00%	5.96%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Crystal River Unit 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$199,500	94.36	10	$226,300	9506.7	
	9	$179,550	93.88	9	$203,670	9514.2	
****	8.549	$170,553	93.66	8	$181,040	9521.7	
	8	$159,600	93.39	7	$158,410	9529.2	
	7	$139,650	92.90	6	$135,780	9536.7	
	6	$119,700	92.42	5	$113,150	9544.2	
	5	$99,750	91.93	4.080	$92,330	9551.4	****
	4	$79,800	91.45	4	$90,520	9551.7	
	3	$59,850	90.96	3	$67,890	9559.2	
	2	$39,900	90.47	2	$45,260	9566.7	
	1	$19,950	89.99	1	$22,630	9574.2	
		$0	89.50	0	$0	9581.7	
	0	$0	89.50	0	$0	9656.7	
		$0	89.50	0	$0	9731.7	
	-1	($18,530)	88.31	-1	($22,630)	9739.2	
	-2	($37,060)	87.13	-2	($45,260)	9746.7	
	-3	($55,590)	85.94	-3	($67,890)	9754.2	
	-4	($74,120)	84.75	-4	($90,520)	9761.7	
	-5	($92,650)	83.56	-5	($113,150)	9769.2	
	-6	($111,180)	82.37	-6	($135,780)	9776.7	
	-7	($129,710)	81.19	-7	($158,410)	9784.2	
	-8	($148,240)	80.00	-8	($181,040)	9791.7	
	-9	($166,770)	78.81	-9	($203,670)	9799.2	
	-10	($185,300)	77.62	-10	($226,300)	9806.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.56%	6.31%

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Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Crystal River Unit 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$1,247,300	98.44	10	$358,700	10277.0	
	10	$1,247,300	95.06	9	$322,830	10284.5	
	9	$1,122,570	94.62	8	$286,960	10292.0	
	8	$997,840	94.19	7	$251,090	10299.5	
	7	$873,110	93.75	6	$215,220	10307.0	
	6	$748,380	93.32	5	$179,350	10314.5	
	5	$623,650	92.88	4.721	$169,342	10316.6	****
	4	$498,920	92.45	4	$143,480	10322.0	
	3	$374,190	92.01	3	$107,610	10329.5	
	2	$249,460	91.58	2	$71,740	10337.0	
	1	$124,730	91.14	1	$35,870	10344.5	
		$0	90.71	0	$0	10352.0	
	0	$0	90.71	0	$0	10427.0	
		$0	90.71	0	$0	10502.0	
	-1	($241,310)	89.83	-1	($35,870)	10509.5	
	-2	($482,620)	88.95	-2	($71,740)	10517.0	
	-3	($723,930)	88.07	-3	($107,610)	10524.5	
	-4	($965,240)	87.19	-4	($143,480)	10532.0	
	-5	($1,206,550)	86.31	-5	($179,350)	10539.5	
	-6	($1,447,860)	85.43	-6	($215,220)	10547.0	
	-7	($1,689,170)	84.55	-7	($251,090)	10554.5	
	-8	($1,930,480)	83.67	-8	($286,960)	10562.0	
	-9	($2,171,790)	82.79	-9	($322,830)	10569.5	
	-10	($2,413,100)	81.91	-10	($358,700)	10577.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
34.77%	10.00%

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Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Crystal River Unit 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$149,700	95.68	10	$319,500	9310.4	
	9	$134,730	95.30	9	$287,550	9317.9	
	8	$119,760	94.92	8	$255,600	9325.4	
	7	$104,790	94.54	7	$223,650	9332.9	
	6	$89,820	94.17	6	$191,700	9340.4	
	5	$74,850	93.79	5	$159,750	9347.9	
	4	$59,880	93.41	4	$127,800	9355.4	
	3	$44,910	93.03	3	$95,850	9362.9	
	2	$29,940	92.65	2	$63,900	9370.4	
	1	$14,970	92.27	1	$31,950	9377.9	
		$0	91.89	0	$0	9385.4	
	0	$0	91.89	0	$0	9460.4	
		$0	91.89	0	$0	9535.4	
	-1	($39,030)	91.13	-0.715	($22,844)	9540.4	****
	-2	($78,060)	90.37	-1	($31,950)	9542.9	
	-3	($117,090)	89.61	-2	($63,900)	9550.4	
	-4	($156,120)	88.86	-3	($95,850)	9557.9	
	-5	($195,150)	88.10	-4	($127,800)	9565.4	
	-6	($234,180)	87.34	-5	($159,750)	9572.9	
	-7	($273,210)	86.58	-6	($191,700)	9580.4	
	-8	($312,240)	85.82	-7	($223,650)	9587.9	
	-9	($351,270)	85.06	-8	($255,600)	9595.4	
****	-9.389	($366,453)	84.76	-9	($287,550)	9602.9	
	-10	($390,300)	84.30	-10	($319,500)	9610.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.17%	8.91%

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Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Crystal River Unit 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$96,100	90.92	10	$387,400	9151.1	
	9	$86,490	90.79	9	$348,660	9158.6	
	8	$76,880	90.66	8	$309,920	9166.1	
	7	$67,270	90.53	7	$271,180	9173.6	
	6	$57,660	90.39	6	$232,440	9181.1	
	5	$48,050	90.26	5	$193,700	9188.6	
	4	$38,440	90.13	4	$154,960	9196.1	
	3	$28,830	90.00	3	$116,220	9203.6	
	2	$19,220	89.86	2	$77,480	9211.1	
	1	$9,610	89.73	1	$38,740	9218.6	
		$0	89.60		$0	9226.1	
	0	$0	89.60	0	$0	9301.1	
		$0	89.60	0.000	$0	9361.3	****
	-1	($12,730)	89.33		$0	9376.1	
	-2	($25,460)	89.05	-1	($31,950)	9383.6	
	-3	($38,190)	88.78	-2	($63,900)	9391.1	
	-4	($50,920)	88.50	-3	($95,850)	9398.6	
	-5	($63,650)	88.23	-4	($127,800)	9406.1	
	-6	($76,380)	87.95	-5	($159,750)	9413.6	
	-7	($89,110)	87.68	-6	($191,700)	9421.1	
	-8	($101,840)	87.40	-7	($223,650)	9428.6	
	-9	($114,570)	87.13	-8	($255,600)	9436.1	
	-10	($127,300)	86.85	-9	($287,550)	9443.6	
****	-10.000	($127,300)	77.79	-10	($387,400)	9451.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.68%	10.80%

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Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Anclote 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$30,100	90.47	10	$157,900	9904.1	
	9	$27,090	90.30	9	$142,110	9925.3	
	8	$24,080	90.13	8	$126,320	9946.6	
****	7.115	$21,416	89.97	7	$110,530	9967.8	
	7	$21,070	89.96	6	$94,740	9989.1	
	6	$18,060	89.79	5	$78,950	10010.3	
	5	$15,050	89.62	4	$63,160	10031.5	
	4	$12,040	89.45	3	$47,370	10052.8	
	3	$9,030	89.28	2	$31,580	10074.0	
	2	$6,020	89.11	1	$15,790	10095.3	
	1	$3,010	88.94	0	$0	10116.5	
		$0	88.77	0	$0	10191.5	
	0	$0	88.77	0.000	$0	10199.8	****
		$0	88.77	0	$0	10266.5	
	-1	($5,260)	88.42	-1	($15,790)	10287.7	
	-2	($10,520)	88.08	-2	($31,580)	10309.0	
	-3	($15,780)	87.73	-3	($47,370)	10330.2	
	-4	($21,040)	87.39	-4	($63,160)	10351.5	
	-5	($26,300)	87.04	-5	($78,950)	10372.7	
	-6	($31,560)	86.70	-6	($94,740)	10393.9	
	-7	($36,820)	86.35	-7	($110,530)	10415.2	
	-8	($42,080)	86.01	-8	($126,320)	10436.4	
	-9	($47,340)	85.66	-9	($142,110)	10457.7	
	-10	($52,600)	85.32	-10	($157,900)	10478.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.84%	4.40%

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Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Company: Florida Power Corporation
Period of: October 1998 - December 1998
Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$8,200	45.94	10	$85,500	9955.4	
	10	$8,200	45.87	9	$76,950	9980.8	
	9	$7,380	45.79	8	$68,400	10006.2	
	8	$6,560	45.71	7	$59,850	10031.6	
	7	$5,740	45.63	6	$51,300	10057.0	
	6	$4,920	45.55	5	$42,750	10082.4	
	5	$4,100	45.47	4	$34,200	10107.8	
	4	$3,280	45.39	3	$25,650	10133.2	
	3	$2,460	45.31	2	$17,100	10158.6	
	2	$1,640	45.23	1	$8,550	10184.0	
	1	$820	45.15	0	$0	10209.4	
		$0	45.07	0	$0	10284.4	
	0	$0	45.07	0	$0	10359.4	
		$0	45.07	-0.431	($3,685)	10370.0	****
	-1	($2,190)	44.91	-1	($8,550)	10384.8	
	-2	($4,380)	44.75	-2	($17,100)	10410.2	
	-3	($6,570)	44.58	-3	($25,650)	10435.6	
	-4	($8,760)	44.42	-4	($34,200)	10461.0	
	-5	($10,950)	44.26	-5	($42,750)	10486.4	
	-6	($13,140)	44.09	-6	($51,300)	10511.8	
	-7	($15,330)	43.93	-7	($59,850)	10537.2	
	-8	($17,520)	43.77	-8	($68,400)	10562.6	
	-9	($19,710)	43.60	-9	($76,950)	10588.0	
	-10	($21,900)	43.44	-10	($85,500)	10613.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.23%	2.38%

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Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 1	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	100.00	87.81	75.31	87.71
2. PH	745	720	744	2209
3. SH	745.0	613.8	353.2	1712.0
4. RSH	0.0	106.2	224.7	330.8
5. UH	0.0	0.0	166.2	166.2
6. POH	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	72.9	72.9
8. MOH	0.0	0.0	93.4	93.4
9. PFOH	0.0	8.7	85.3	94.0
10. LR PF (MW)	0.0	371.9	76.3	103.7
11. PMOH	0.0	79.1	0.0	79.1
12. LR PM (MW)	0.0	372.0	0.0	372.0
13. NSC (MW)	372	372	372	372
14. OPER MBTU	2386574	1668719	947225	5002518
15. NET GEN (MWH)	244202	171322	96358	511882
16. ANOHR (BTU/KWH)	9772.9	9740.3	9830.3	9772.8
17. NOF (%)	88.12	75.03	73.35	80.4
18. NPC (MW)	372	372	372	372

ANOHR EQUATION: ANOHR= -15.984 x NOF + 11085

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EFFECTIVE:
DOCKET NO.:
ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 2	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	100.00	88.81	91.99	93.66
2. PH	745	720	744	2209
3. SH	745.0	720.0	695.2	2160.2
4. RSH	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	48.8	48.8
6. POH	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	48.8	48.8
8. MOH	0.0	0.0	0.0	0.0
9. PFOH	0.0	81.3	7.5	88.8
10. LR PF (MW)	0.0	446.4	117.1	418.7
11. PMOH	0.0	3.0	52.8	55.8
12. LR PM (MW)	0.0	468.0	79.5	100.4
13. NSC (MW)	468	468	468	468
14. OPER MBTU	2445862	2409731	2132627	6988220
15. NET GEN (MWH)	250401	247683	217343	715427
16. ANOHR (BTU/KWH)	9767.8	9729.1	9812.3	9767.9
17. NOF (%)	71.82	73.51	66.80	70.8
18. NPC (MW)	468	468	468	468

ANOHR EQUATION: ANOHR= -9.263 x NOF + 10529

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DOCKET NO.:
ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 3	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	99.97	95.33	99.91	98.44
2. PH	745	720	744	2209
3. SH	745.0	720.0	744.0	2209.0
4. RSH	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0
6. POH	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	0.0
9. PFOH	0.0	29.3	0.0	29.3
10. LR PF (MW)	0.0	852.4	0.0	852.4
11. PMOH	3.3	0.0	10.9	14.3
12. LR PM (MW)	48.6	0.0	47.5	47.8
13. NSC (MW)	743	743	743	743
14. OPER MBTU	5835752	5619615	5833844	17289211
15. NET GEN (MWH)	571603	552170	573117	1696890
16. ANOHR (BTU/KWH)	10209.4	10177.3	10179.2	10188.8
17. NOF (%)	103.26	103.22	103.68	103.4
18. NPC (MW)	743	743	743	743

ANOHR EQUATION: ANOHR= -28.08 x NOF + 13202.3

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DOCKET NO.:
ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 4	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	98.36	58.38	96.67	84.76
2. PH	745	720	744	2209
3. SH	745.0	656.1	719.3	2120.4
4. RSH	0.0	0.0	0.0	0.0
5. UH	0.0	63.9	24.8	88.7
6. POH	0.0	0.0	0.0	0.0
7. FOH	0.0	63.9	24.8	88.7
8. MOH	0.0	0.0	0.0	0.0
9. PFOH	7.6	0.0	0.0	7.6
10. LR PF (MW)	111.2	0.0	0.0	111.2
11. PMOH	160.2	241.6	0.0	401.9
12. LR PM (MW)	47.7	680.0	0.0	427.9
13. NSC (MW)	697	697	697	697
14. OPER MBTU	4370626	3516991	3440492	11328110
15. NET GEN (MWH)	466789	369744	357966	1194499
16. ANOHR (BTU/KWH)	9363.2	9512.0	9611.2	9483.6
17. NOF (%)	89.89	80.85	71.41	80.8
18. NPC (MW)	697	697	697	697

ANOHR EQUATION: ANOHR= -7.218 x NOF + 9986.6

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DOCKET NO.:
ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

CRYSTAL RIVER 5	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	99.27	62.80	89.84	84.21
2. PH	745	720	744	2209
3. SH	745.0	710.3	676.1	2131.5
4. RSH	0.0	0.0	0.0	0.0
5. UH	0.0	9.7	67.9	77.5
6. POH	0.0	0.0	0.0	0.0
7. FOH	0.0	9.7	0.0	9.7
8. MOH	0.0	0.0	67.9	67.9
9. PFOH	10.3	89.9	0.0	100.3
10. LR PF (MW)	365.9	697.0	0.0	662.9
11. PMOH	0.0	168.2	113.2	281.4
12. LR PM (MW)	0.0	697.0	47.7	435.9
13. NSC (MW)	697	697	697	697
14. OPER MBTU	4308852	3807197	2994160	11110209
15. NET GEN (MWH)	462328	404772	313160	1180260
16. ANOHR (BTU/KWH)	9319.9	9405.8	9561.1	9413.4
17. NOF (%)	89.04	81.76	66.45	79.4
18. NPC (MW)	697	697	697	697

ANOHR EQUATION: ANOHR= -3.955 x NOF + 9667.3

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ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 1	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	50.76	97.82	98.83	82.29
2. PH	745	720	744	2209
3. SH	385.5	720.0	744.0	1849.5
4. RSH	0.0	0.0	0.0	0.0
5. UH	359.5	0.0	0.0	359.5
6. POH	342.5	0.0	0.0	342.5
7. FOH	17.1	0.0	0.0	17.1
8. MOH	0.0	0.0	0.0	0.0
9. PFOH	146.8	24.7	14.0	185.4
10. LR PF (MW)	14.6	165.8	319.1	57.7
11. PMOH	10.2	24.1	0.0	34.3
12. LR PM (MW)	155.0	163.4	0.0	160.9
13. NSC (MW)	511	511	511	511
14. OPER MBTU	1018509	2309155	2780031	6107694
15. NET GEN (MWH)	100809	237979	288674	627462
16. ANOHR (BTU/KWH)	10103.3	9703.2	9630.3	9734.0
17. NOF (%)	51.18	64.68	75.93	66.4
18. NPC (MW)	511	511	511	511

ANOHR EQUATION: ANOHR= -17.598 x NOF + 10894.6

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EFFECTIVE:
DOCKET NO.:
ORDER NO.:

ACTUAL UNIT PERFORMANCE DATA

FLORIDA POWER CORPORATION

ANCLOTE 2	Oct-98	Nov-98	Dec-98	Oct-Dec Period
1. EAF	68.94	0.00	61.40	43.93
2. PH	745	720	744	2209
3. SH	528.6	0.0	458.8	987.4
4. RSH	0.0	0.0	0.0	0.0
5. UH	216.5	720.0	285.2	1221.6
6. POH	216.5	720.0	285.2	1221.6
7. FOH	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	0.0
9. PFOH	0.0	0.0	2.4	2.4
10. LR PF (MW)	0.0	0.0	427.7	427.7
11. PMOH	44.8	0.0	0.0	44.8
12. LR PM (MW)	170.4	0.0	0.0	170.4
13. NSC (MW)	511	511	511	511
14. OPER MBTU	1629295	0	1783414	3412709
15. NET GEN (MWH)	164102	0	187521	351623
16. ANOHR (BTU/KWH)	9928.6	0.0	9510.5	9705.6
17. NOF (%)	60.76	0.00	79.98	69.7
18. NPC (MW)	511	511	511	511

ANOHR EQUATION: ANOHR= -17.966 x NOF + 10871.7

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DOCKET NO.:
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PLANNED OUTAGE SCHEDULES
ACTUAL

Company: Florida Power Corporation
Period of: October 1998 - December 1998

Plant/Unit	Actual Outage Dates	Reason for Outage (1)
1998		
Anclote 1	10/07 (00:48) - 10/21 (07:15)	Inspection
Anclote 2	10/23 (00:33) - 12/12 (21:11)	Gas Conversion/Boiler Controls

(1) To be acommpanied by a critical path bar chart or milestone date chart of major activity to be performed during the outage.

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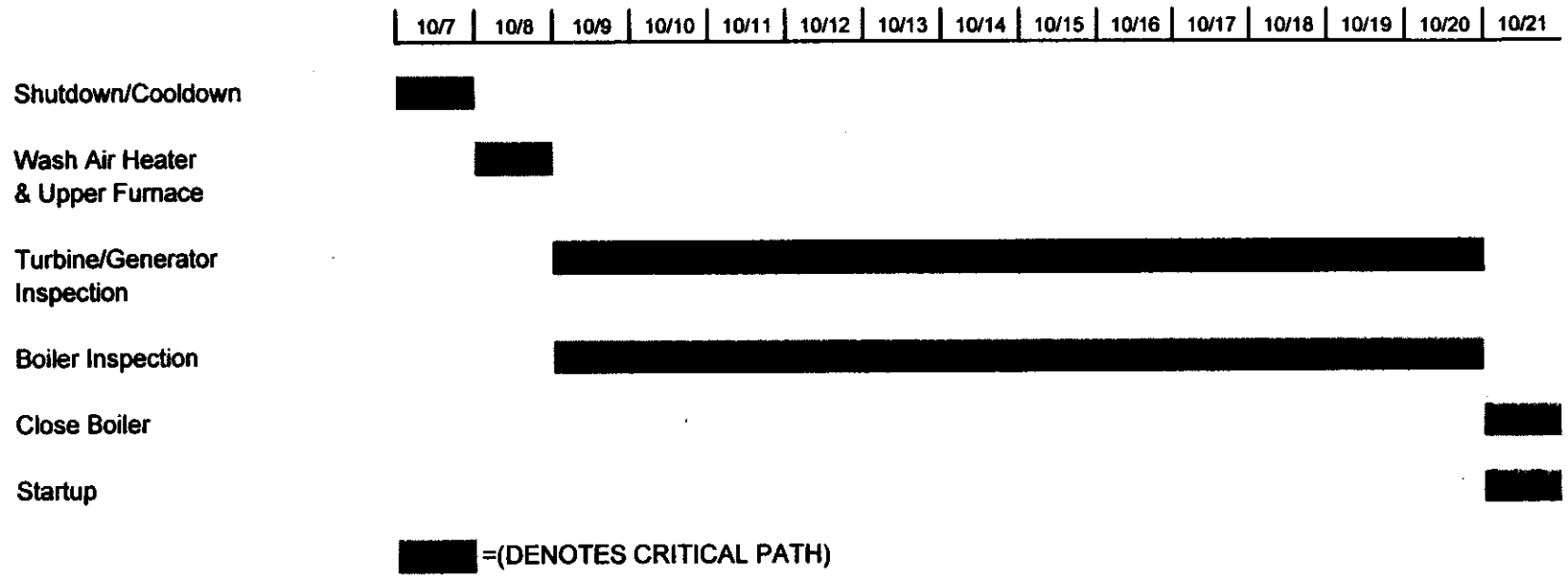
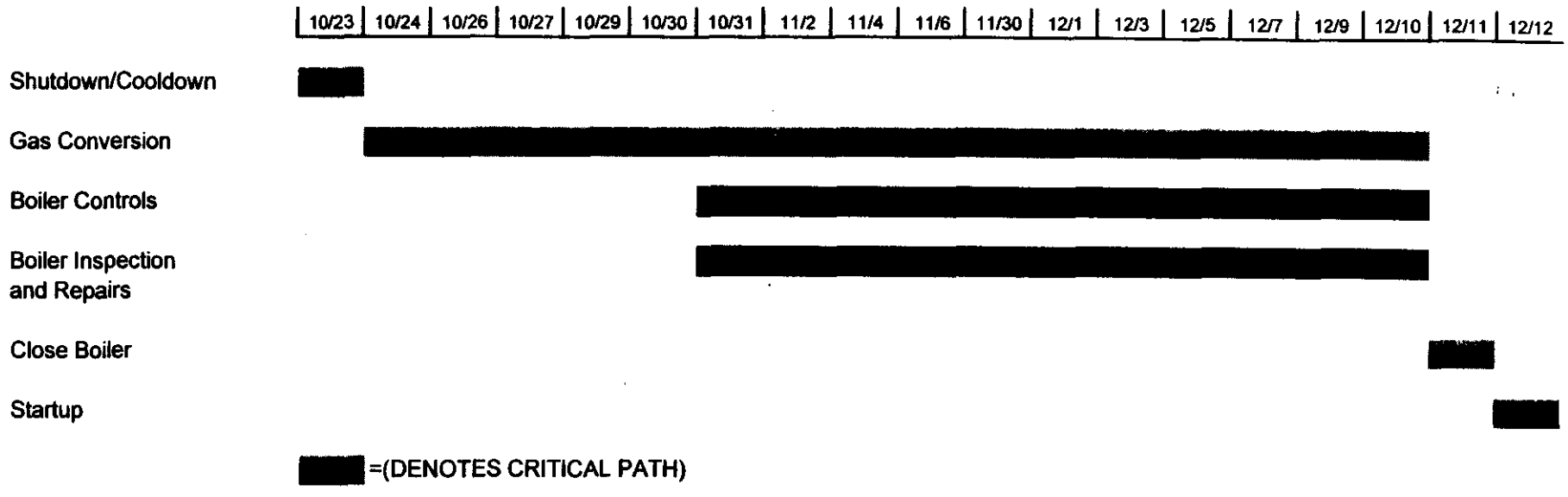
FLORIDA POWER CORPORATION
ACTUAL FOR ANCLOTE #1 1998 INSPECTION

(indicating dates ending midnight)



FLORIDA POWER CORPORATION
ACTUAL FOR ANCLOTE #2 1998 GAS CONVERSION/BOILER CONTROLS

(indicating dates ending midnight)



9

EXHIBITS TO THE TESTIMONY OF REBECCA J. MCCLINTOCK

GPIF TARGETS AND RANGES FOR JANUARY THROUGH DECEMBER 2000

STANDARD FORM GPIF SCHEDULES

Description	Page
Reward/Penalty Table (Estimated)	1
Maximum Incentive Dollars (Estimated)	2
Target and Range Summary	3
Comparison of Targets with Prior Period Performance	4-5
Derivation of Weighting Factors	6
Incentive Point Tables	7-15
Unit Performance Data (Estimated)	16-24
Planned Outage Schedules (Estimated)	25-26
Average Net Operating Heat Rate Curves	27-44
Unplanned Outage Rate Tables and Graphs	45-90

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 9
COMPANY/ WITNESS: R. McClintock
DATE: 11-22-99

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$24,864,477	$7,614,184
9	$22,378,029	$6,852,766
8	$19,891,582	$6,091,347
7	$17,405,134	$5,329,929
6	$14,918,686	$4,568,511
5	$12,432,238	$3,807,092
4	$9,945,791	$3,045,674
3	$7,459,343	$2,284,255
2	$4,972,895	$1,522,837
1	$2,486,448	$761,418
0	$0	$0
-1	($4,354,348)	($761,418)
-2	($8,708,695)	($1,522,837)
-3	($13,063,043)	($2,284,255)
-4	($17,417,391)	($3,045,674)
-5	($21,771,738)	($3,807,092)
-6	($26,126,086)	($4,568,511)
-7	($30,480,434)	($5,329,929)
-8	($34,834,782)	($6,091,347)
-9	($39,189,129)	($6,852,766)
-10	($43,543,477)	($7,614,184)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

1	Beginning of period balance of common equity	$1,879,776,874	
2	END OF MONTH BALANCE OF COMMON EQUITY:		
	Month of JANUARY 2000	$1,899,299,544	
3	Month of FEBRUARY 2000	$1,914,080,909	
4	Month of MARCH 2000	$1,878,293,622	
5	Month of APRIL 2000	$1,887,057,300	
6	Month of MAY 2000	$1,915,345,962	
7	Month of JUNE 2000	$1,893,359,787	
8	Month of JULY 2000	$1,929,934,399	
9	Month of AUGUST 2000	$1,967,739,300	
10	Month of SEPTEMBER 2000	$1,947,877,041	
11	Month of OCTOBER 2000	$1,968,276,039	
12	Month of NOVEMBER 2000	$1,979,438,356	
13	Month of DECEMBER 2000	$1,947,438,937	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$1,923,686,005	
15	25 Basis Points	$0.0025	
16	Revenue Expansion Factor	61.3738%	
17	*Maximum allowed incentive* dollars (LINE 14 times LINE 15 divided by LINE 16)	$7,835,941	
18	Jurisdictional Sales *	34,558,606	MWH
19	Total Sales *	35,563,283	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	97.17%	
21	Maximum allowed jurisdictional *incentive dollars* (LINE 17 times LINE 20)	$7,614,184	

* *Net sales (Sales - Interruptible)*

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GPIF TARGET AND RANGE SUMMARY

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
ANCLOTE 1	4.71	92.36	94.15	88.68	1172	(2,142.0)
ANCLOTE 2	5.88	83.94	86.98	77.78	1463	(1,990.0)
BARTOW 3	1.68	82.84	86.39	75.71	418	(2,026.0)
C.R. 1	3.46	90.28	94.81	81.24	860	(3,595.0)
C.R. 2	10.80	75.25	79.85	66.34	2685	(4,532.0)
C.R. 3	10.49	93.43	96.52	87.09	2608	(7,700.0)
C.R. 4	9.68	75.65	78.97	69.01	2407	(5,122.0)
C.R. 5	3.60	94.04	95.95	90.09	896	(2,695.0)
TIGER BAY	1.26	79.13	82.32	75.96	314	(1,700.0)
GPIF System	51.57				12823	(31,502.0)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (%)	ANOHR RANGE Max. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
ANCLOTE 1	5.16	10022	52.0	9744	10300	1281.8	(1,281.8)
ANCLOTE 2	4.42	10025	53.2	9767	10283	1100.2	(1,100.2)
BARTOW 3	2.15	10140	61.1	9860	10420	533.8	(533.8)
C.R. 1	3.24	9851	82.4	9671	10032	805.5	(805.5)
C.R. 2	2.63	9851	68.7	9687	10014	653.5	(653.5)
C.R. 3	10.50	10357	100.2	10207	10507	2610.2	(2,610.2)
C.R. 4	6.36	9422	89.6	9248	9596	1581.6	(1,581.6)
C.R. 5	8.66	9394	91.5	9205	9582	2154.4	(2,154.4)
TIGER BAY	5.31	7590	90.0	7000	8180	1320.5	(1,320.5)
GPIF System	48.43					12041.5	(12,041.5)

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Oct.-Dec. 98 POF	EUOF	EUOR	Actual Performance 2nd Prior Period SUMMER 98 POF	EUOF	EUOR
ANCLOTE 1	4.71	9.14	3.83	3.82	4.97	15.50	2.21	2.62	0.00	2.84	2.87
ANCLOTE 2	5.88	11.41	9.56	6.50	9.03	55.30	0.77	1.72	0.00	26.40	26.70
BARTOW 3	1.68	3.26	9.56	7.60	10.94	29.49	2.59	3.76	2.72	8.34	4.25
C.R. 1	3.46	6.71	0.00	9.72	9.97	0.00	12.30	14.46	30.98	9.88	14.55
C.R. 2	10.80	20.94	14.75	9.99	12.29	0	6.35	6.35	0.00	38.11	38.55
C.R. 3	10.49	20.34	0.00	6.57	6.57	0.00	1.56	1.56	0.00	2.16	2.16
C.R. 4	9.68	18.77	17.21	7.14	8.63	0.00	15.24	15.24	22.93	4.66	6.13
C.R. 5	3.60	6.99	1.91	4.05	4.15	0.00	15.80	15.80	0.00	5.57	5.66
TIGER BAY	1.26	2.45	15.30	5.57	9.22	0.00	29.64	37.71	18.06	15.09	8.34
GPIF System Wghtd. Avg.	51.57	100.00	8.58	7.18	8.56	8.69	7.54	8.06	6.91	14.26	14.69

Plant/Unit	Actual Performance 3rd Prior Period WTR 97/98 POF	EUOF	EUOR	Actual Performance 4th Prior Period SUMMER 97 POF	EUOF	EUOR	Actual Performance 5th Prior Period WTR 96/97 POF	EUOF	EUOR
ANCLOTE 1	19.31	0.90	1.62	0.00	4.39	4.59	0.00	7.14	12.98
ANCLOTE 2	11.94	2.96	3.86	0.00	6.99	7.45	39.61	0.73	1.68
BARTOW 3	21.01	5.22	6.88	1.05	21.47	21.70	0.00	6.48	6.56
C.R. 1	0.00	5.30	5.30	0.00	5.63	5.63	26.80	5.22	7.13
C.R. 2	0.00	17.00	17.00	2.53	9.48	9.72	19.88	8.83	11.02
C.R. 3	67.59	5.74	17.72	0.00	0.00	0.00	0.00	0.00	0.00
C.R. 4	13.66	9.29	10.76	0.00	1.34	1.34	0.00	17.54	17.54
C.R. 5	0.00	1.36	1.38	16.34	0.82	0.98	1.59	2.24	2.27
TIGER BAY	0.00	0.19	0.19	0.00	0.18	0.42	n/a	n/a	n/a
GPIF System Wghtd. Avg.	20.12	7.52	10.45	1.71	4.57	4.72	10.59	6.60	7.83

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan. 1998 - Dec. 1998	2nd Prior HR Jan. 1997 - Dec. 1997	3rd Prior HR Jan. 1996 - Dec. 1996
ANCLOTE 1	5.16	10.65	10022	10005	10004	10005
ANCLOTE 2	4.42	9.14	10025	10016	10002	9951
BARTOW 3	2.15	4.43	10140	10072	10132	10098
C.R. 1	3.24	6.69	9851	9817	9847	9885
C.R. 2	2.63	5.43	9851	9823	9837	9883
C.R. 3	10.50	21.68	10357	10335	10376	10423
C.R. 4	6.36	13.13	9422	9439	9425	9347
C.R. 5	8.66	17.89	9394	9425	9355	9316
TIGER BAY	5.31	10.97	7590	7511	n/a	n/a
GPIF System Weighted Avg.	48.43	100.00	9621	9607	9605	9597

NOTE: FPC ownership of Tiger Bay began in July 1997; therefore, its heat rate performance is not known before that date.

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DERIVATION OF WEIGHTING FACTORS

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

Production Costing Simulation
Fuel Cost ($000)

Unit Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
ANC. 1 EA	1048708	1047536	1172	4.71
ANC. 1 HR	1048708	1047426	1282	5.16
ANC. 2 EA	1048708	1047245	1463	5.88
ANC. 2 HR	1048708	1047608	1100	4.42
BARTOW 3 EA	1048708	1048290	418	1.68
BARTOW 3 HR	1048708	1048174	534	2.15
C.R. 1 EA	1048708	1047848	860	3.46
C.R. 1 HR	1048708	1047902	806	3.24
C.R. 2 EA	1048708	1046023	2685	10.80
C.R. 2 HR	1048708	1048055	653	2.63
C.R. 3 EA	1048708	1046100	2608	10.49
C.R. 3 HR	1048708	1046098	2610	10.50
C.R. 4 EA	1048708	1046301	2407	9.68
C.R. 4 HR	1048708	1047126	1582	6.36
C.R. 5 EA	1048708	1047812	896	3.60
C.R. 5 HR	1048708	1046554	2154	8.66
TIGER BAY EA	1048708	1048394	314	1.26
TIGER BAY HR	1048708	1047387	1321	5.31

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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Docket No:
Order No.:

INCENTIVE POINT TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Anclote 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,172,000	94.15	10	$1,281,848	9743.5
9	$1,054,800	93.97	9	$1,153,664	9763.9
8	$937,600	93.79	8	$1,025,479	9784.2
7	$820,400	93.61	7	$897,294	9804.6
6	$703,200	93.43	6	$769,109	9824.9
5	$586,000	93.25	5	$640,924	9845.2
4	$468,800	93.07	4	$512,739	9865.6
3	$351,600	92.89	3	$384,555	9885.9
2	$234,400	92.71	2	$256,370	9906.2
1	$117,200	92.54	1	$128,185	9926.6
					9946.9
0	$0	92.36	0	$0	10021.9
					10096.9
-1	($214,200)	91.99	-1	($128,185)	10117.3
-2	($428,400)	91.62	-2	($256,370)	10137.6
-3	($642,600)	91.25	-3	($384,555)	10157.9
-4	($856,800)	90.89	-4	($512,739)	10178.3
-5	($1,071,000)	90.52	-5	($640,924)	10198.6
-6	($1,285,200)	90.15	-6	($769,109)	10218.9
-7	($1,499,400)	89.78	-7	($897,294)	10239.3
-8	($1,713,600)	89.41	-8	($1,025,479)	10259.6
-9	($1,927,800)	89.05	-9	($1,153,664)	10280.0
-10	($2,142,000)	88.68	-10	($1,281,848)	10300.3

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.71%	5.16%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Anclote 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,463,000	86.98	10	$1,100,183	9766.8
9	$1,316,700	86.68	9	$990,165	9785.1
8	$1,170,400	86.37	8	$880,147	9803.4
7	$1,024,100	86.07	7	$770,128	9821.7
6	$877,800	85.76	6	$660,110	9840.0
5	$731,500	85.46	5	$550,092	9858.3
4	$585,200	85.15	4	$440,073	9876.6
3	$438,900	84.85	3	$330,055	9894.9
2	$292,600	84.54	2	$220,037	9913.2
1	$146,300	84.24	1	$110,018	9931.5
					9949.8
0	$0	83.94	0	$0	10024.8
					10099.8
-1	($199,000)	83.32	-1	($110,018)	10118.1
-2	($398,000)	82.70	-2	($220,037)	10136.4
-3	($597,000)	82.09	-3	($330,055)	10154.7
-4	($796,000)	81.47	-4	($440,073)	10173.0
-5	($995,000)	80.86	-5	($550,092)	10191.3
-6	($1,194,000)	80.24	-6	($660,110)	10209.6
-7	($1,393,000)	79.63	-7	($770,128)	10227.9
-8	($1,592,000)	79.01	-8	($880,147)	10246.2
-9	($1,791,000)	78.40	-9	($990,165)	10264.5
-10	($1,990,000)	77.78	-10	($1,100,183)	10282.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.88%	4.42%

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Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Crystal River 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$860,000	94.81	10	$805,537	9670.7
9	$774,000	94.36	9	$724,983	9681.3
8	$688,000	93.91	8	$644,429	9691.9
7	$602,000	93.45	7	$563,876	9702.5
6	$516,000	93.00	6	$483,322	9713.0
5	$430,000	92.55	5	$402,768	9723.6
4	$344,000	92.10	4	$322,215	9734.2
3	$258,000	91.64	3	$241,661	9744.8
2	$172,000	91.19	2	$161,107	9755.3
1	$86,000	90.74	1	$80,554	9765.9
					9776.5
0	$0	90.28	0	$0	9851.5
					9926.5
-1	($359,500)	89.38	-1	($80,554)	9937.1
-2	($719,000)	88.48	-2	($161,107)	9947.6
-3	($1,078,500)	87.57	-3	($241,661)	9958.2
-4	($1,438,000)	86.67	-4	($322,215)	9968.8
-5	($1,797,500)	85.76	-5	($402,768)	9979.4
-6	($2,157,000)	84.86	-6	($483,322)	9989.9
-7	($2,516,500)	83.96	-7	($563,876)	10000.5
-8	($2,876,000)	83.05	-8	($644,429)	10011.1
-9	($3,235,500)	82.15	-9	($724,983)	10021.7
-10	($3,595,000)	81.24	-10	($805,537)	10032.3

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.46%	3.24%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Crystal River 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,685,000	79.85	10	$653,492	9687.2
9	$2,416,500	79.39	9	$588,143	9696.1
8	$2,148,000	78.93	8	$522,794	9704.9
7	$1,879,500	78.47	7	$457,445	9713.8
6	$1,611,000	78.01	6	$392,095	9722.7
5	$1,342,500	77.55	5	$326,746	9731.5
4	$1,074,000	77.09	4	$261,397	9740.4
3	$805,500	76.63	3	$196,048	9749.3
2	$537,000	76.17	2	$130,698	9758.1
1	$268,500	75.71	1	$65,349	9767.0
					9775.8
0	$0	75.25	0	$0	9850.8
					9925.8
-1	($453,200)	74.36	-1	($65,349)	9934.7
-2	($906,400)	73.47	-2	($130,698)	9943.6
-3	($1,359,600)	72.58	-3	($196,048)	9952.4
-4	($1,812,800)	71.69	-4	($261,397)	9961.3
-5	($2,266,000)	70.80	-5	($326,746)	9970.2
-6	($2,719,200)	69.91	-6	($392,095)	9979.0
-7	($3,172,400)	69.02	-7	($457,445)	9987.9
-8	($3,625,600)	68.13	-8	($522,794)	9996.7
-9	($4,078,800)	67.24	-9	($588,143)	10005.6
-10	($4,532,000)	66.34	-10	($653,492)	10014.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.80%	2.63%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Crystal River 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,608,000	96.52	10	$2,610,155	10207.0
9	$2,347,200	96.21	9	$2,349,139	10214.5
8	$2,086,400	95.90	8	$2,088,124	10222.0
7	$1,825,600	95.60	7	$1,827,108	10229.5
6	$1,564,800	95.29	6	$1,566,093	10237.0
5	$1,304,000	94.98	5	$1,305,077	10244.5
4	$1,043,200	94.67	4	$1,044,062	10252.0
3	$782,400	94.36	3	$783,046	10259.5
2	$521,600	94.05	2	$522,031	10267.0
1	$260,800	93.74	1	$261,015	10274.5
					10282.0
0	$0	93.43	0	$0	10357.0
					10432.0
-1	($770,000)	92.80	-1	($261,015)	10439.5
-2	($1,540,000)	92.16	-2	($522,031)	10447.0
-3	($2,310,000)	91.53	-3	($783,046)	10454.5
-4	($3,080,000)	90.90	-4	($1,044,062)	10462.0
-5	($3,850,000)	90.26	-5	($1,305,077)	10469.5
-6	($4,620,000)	89.63	-6	($1,566,093)	10477.0
-7	($5,390,000)	88.99	-7	($1,827,108)	10484.5
-8	($6,160,000)	88.36	-8	($2,088,124)	10492.0
-9	($6,930,000)	87.73	-9	($2,349,139)	10499.5
-10	($7,700,000)	87.09	-10	($2,610,155)	10507.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.49%	10.50%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,407,000	78.97	10	$1,581,607	9247.8
9	$2,166,300	78.64	9	$1,423,446	9257.7
8	$1,925,600	78.31	8	$1,265,285	9267.6
7	$1,684,900	77.98	7	$1,107,125	9277.5
6	$1,444,200	77.64	6	$948,964	9287.4
5	$1,203,500	77.31	5	$790,803	9297.3
4	$962,800	76.98	4	$632,643	9307.2
3	$722,100	76.65	3	$474,482	9317.1
2	$481,400	76.31	2	$316,321	9327.0
1	$240,700	75.98	1	$158,161	9336.9
					9346.8
0	$0	75.65	0	$0	9421.8
					9496.8
-1	($512,200)	74.98	-1	($158,161)	9506.7
-2	($1,024,400)	74.32	-2	($316,321)	9516.6
-3	($1,536,600)	73.66	-3	($474,482)	9526.5
-4	($2,048,800)	72.99	-4	($632,643)	9536.4
-5	($2,561,000)	72.33	-5	($790,803)	9546.3
-6	($3,073,200)	71.66	-6	($948,964)	9556.2
-7	($3,585,400)	71.00	-7	($1,107,125)	9566.1
-8	($4,097,600)	70.34	-8	($1,265,285)	9576.0
-9	($4,609,800)	69.67	-9	($1,423,446)	9585.9
-10	($5,122,000)	69.01	-10	($1,581,607)	9595.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
9.68%	6.36%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$896,000	95.95	10	$2,154,370	9204.8
9	$806,400	95.76	9	$1,938,933	9216.2
8	$716,800	95.57	8	$1,723,496	9227.6
7	$627,200	95.38	7	$1,508,059	9238.9
6	$537,600	95.19	6	$1,292,622	9250.3
5	$448,000	94.99	5	$1,077,185	9261.7
4	$358,400	94.80	4	$861,748	9273.1
3	$268,800	94.61	3	$646,311	9284.5
2	$179,200	94.42	2	$430,874	9295.9
1	$89,600	94.23	1	$215,437	9307.2
					9318.6
0	$0	94.04	0	$0	9393.6
					9468.6
-1	($269,500)	93.64	-1	($215,437)	9480.0
-2	($539,000)	93.25	-2	($430,874)	9491.4
-3	($808,500)	92.86	-3	($646,311)	9502.8
-4	($1,078,000)	92.46	-4	($861,748)	9514.2
-5	($1,347,500)	92.07	-5	($1,077,185)	9525.5
-6	($1,617,000)	91.67	-6	($1,292,622)	9536.9
-7	($1,886,500)	91.28	-7	($1,508,059)	9548.3
-8	($2,156,000)	90.88	-8	($1,723,496)	9559.7
-9	($2,425,500)	90.49	-9	($1,938,933)	9571.1
-10	($2,695,000)	90.09	-10	($2,154,370)	9582.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.60%	8.66%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Florida Power Corporation

Period of: January, 2000 - December, 2000

Unit: Tiger Bay

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$314,000	82.32	10	$1,320,507	6999.8
9	$282,600	82.00	9	$1,188,456	7051.4
8	$251,200	81.69	8	$1,056,406	7102.9
7	$219,800	81.37	7	$924,355	7154.4
6	$188,400	81.05	6	$792,304	7206.0
5	$157,000	80.73	5	$660,253	7257.5
4	$125,600	80.41	4	$528,203	7309.0
3	$94,200	80.09	3	$396,152	7360.5
2	$62,800	79.77	2	$264,101	7412.1
1	$31,400	79.45	1	$132,051	7463.6
					7515.1
0	$0	79.13	0	$0	7590.1
					7665.1
-1	($170,000)	78.81	-1	($132,051)	7716.6
-2	($340,000)	78.50	-2	($264,101)	7768.2
-3	($510,000)	78.18	-3	($396,152)	7819.7
-4	($680,000)	77.86	-4	($528,203)	7871.2
-5	($850,000)	77.54	-5	($660,253)	7922.7
-6	($1,020,000)	77.23	-6	($792,304)	7974.3
-7	($1,190,000)	76.91	-7	($924,355)	8025.8
-8	($1,360,000)	76.59	-8	($1,056,406)	8077.3
-9	($1,530,000)	76.28	-9	($1,188,456)	8128.9
-10	($1,700,000)	75.96	-10	($1,320,507)	8180.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.26%	5.31%

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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000 - December, 2000

Anclote 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.77	73.82	95.32	95.11	95.08	95.14	95.06	95.10	92.12	78.04	97.28	97.56	92.36
2. POF	0.00	24.14	0.00	0.00	0.00	0.00	0.00	0.00	3.33	19.35	0.00	0.00	3.83
3. EUOF	2.23	2.04	4.68	4.89	4.92	4.86	4.94	4.90	4.54	2.61	2.72	2.44	3.82
4. EUOR	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97	4.97
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	324.9	278.2	681.9	688.7	715.9	684.8	719.8	714.0	640.1	379.4	383.3	355.1	6566.1
7. RSH	410.0	242.0	43.0	12.0	8.0	16.0	4.0	10.0	38.0	210.0	326.0	379.0	1698.0
8. UH	9.1	175.8	19.1	19.3	20.1	19.2	20.2	20.0	41.9	154.6	10.7	9.9	519.9
9. POH	0	168	0	0	0	0	0	0	24	144	0	0	336.0
10. FOH & EFOH	8.8	7.5	18.5	18.6	19.4	18.5	19.5	19.3	17.3	10.3	10.4	9.6	177.8
11. MOH & EMOH	7.8	6.7	16.4	16.5	17.2	16.5	17.3	17.2	15.4	9.1	9.2	8.5	157.7
12. Oper. Btu(MBtu)	666032	558967	1974041	1790928	1851352	1885357	2069740	2160671	1698764	820620	922915	810385	17221830
13. Net Gen. (MWH)	65712.7	55106	198057.4	178620.9	184593.8	188616.5	207576.1	217364.7	169610.8	81142.8	91697.1	80317.7	1718416.5
14. ANOHR (Btu/KWH)	10136	10143	9967	10026	10029	9996	9971	9940	10016	10113	10065	10090	10022
15. NOF (%)	40.2	39.4	57.7	51.6	51.3	54.8	57.3	60.5	52.7	42.5	47.6	45.0	52.0
16. NSC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503
17. ANOHR Equation	ANOHR=	-9.610 x NOF +		10521.9									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Anclote 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.30	82.73	82.30	91.59	91.65	91.07	91.01	91.05	91.15	81.56	19.35	96.02	83.94
2. POF	0.00	13.79	9.68	0.00	0.00	0.00	0.00	0.00	0.00	12.90	80.00	0.00	9.56
3. EUOF	3.70	3.48	8.02	8.41	8.35	8.93	8.99	8.95	8.85	5.53	0.65	3.98	6.50
4. EUOR	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03	9.03
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	287.7	252.8	623.5	632.9	649.0	671.6	699.0	696.1	665.9	430.1	49.0	309.4	5967.1
7. RSH	439.0	332.0	11.0	49.0	56.0	8.0	3.0	6.0	14.0	192.0	92.0	416.0	1618.0
8. UH	17.3	111.2	109.5	38.1	39.0	40.4	42.0	41.9	40.1	121.9	579.0	18.6	1198.9
9. POH	0	96	72	0	0	0	0	0	0	96	576	0	840.0
10. FOH & EFOH	9.4	8.3	20.5	20.8	21.3	22.1	23.0	22.9	21.9	14.1	1.6	10.2	196.0
11. MOH & EMOH	18.1	15.9	39.2	39.8	40.8	42.2	43.9	43.8	41.9	27.0	3.1	19.4	375.1
12. Oper. Btu(MBtu)	627976	504070	1933956	1726567	1734687	1900141	2046708	2104360	1718396	910242	94362	686631	16009172
13. Net Gen. (MWH)	61754.9	49311.7	195336	172455.9	172989.2	190360.1	205647.3	212041.4	170904.6	89347.2	9213.5	67591.9	1596953.7
14. ANOHR (Btu/KWH)	10169	10222	9901	10012	10028	9982	9953	9924	10055	10188	10242	10158	10025
15. NOF (%)	42.7	38.8	62.3	54.2	53.0	56.4	58.5	60.6	51.0	41.3	37.3	43.4	53.2
16. NSC (MW)	503	503	503	503	503	503	503	503	503	503	503	503	503
17. ANOHR Equation	ANOHR=	-13.676 x NOF +		10752.5									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT **Bartow 3**	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Year*
1. EAF	95.13	82.26	20.32	90.13	90.28	89.78	89.11	89.21	90.07	92.83	93.58	72.36	82.84
2. POF	0.00	13.79	77.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.58	9.56
3. EUOF	4.87	3.94	2.26	9.87	9.72	10.22	10.89	10.79	9.93	7.17	6.42	5.06	7.60
4. EUOR	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94	10.94
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	317.5	240.7	147.7	623.4	634.0	645.5	710.7	704.0	627.2	468.0	405.7	329.9	5854.3
7. RSH	413.0	349.0	14.0	70.0	83.0	47.0	3.0	10.0	66.0	256.0	297.0	232.0	1840.0
8. UH	13.5	106.3	582.3	26.6	27.0	27.5	30.3	30.0	26.8	20.0	17.3	182.1	1089.7
9. POH	0.0	96.0	576.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.0	840.0
10. FOH & EFOH	22.8	17.3	10.6	44.7	45.4	46.3	50.9	50.5	45.0	33.5	29.1	23.6	419.6
11. MOH & EMOH	13.4	10.2	6.3	26.4	26.8	27.3	30.1	29.8	26.6	19.8	17.2	14.0	247.9
12. Oper. Btu(MBtu)	365148	269904	195558	803635	832267	861726	960935	976773	810016	544190	520613	397572	7540697
13. Net Gen. (MWH)	35697.7	26338.8	19330.4	79258.7	82207.9	85240.1	95159.0	96951.0	79899.8	53242.8	51326.4	39001.5	743654.1
14. ANOHR (Btu/KWH)	10229	10247	10117	10139	10124	10109	10098	10075	10138	10221	10143	10194	10140
15. NOF (%)	54.1	52.6	62.9	61.1	62.3	63.5	64.4	66.2	61.2	54.7	60.8	56.8	61.1
16. NSC (MW)	208	208	208	208	208	208	208	208	208	208	208	208	208
17. ANOHR Equation	ANOHR=	-12.673 x NOF +		10914.0									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Crystal River 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	90.88	90.76	90.05	90.55	90.09	90.03	90.03	90.03	90.13	90.53	90.10	90.25	90.28
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	9.12	9.24	9.95	9.45	9.91	9.97	9.97	9.97	9.87	9.47	9.90	9.75	9.72
4. EUOR	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97	9.97
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	639.0	605.2	697.1	640.8	694.3	675.6	698.1	698.1	669.0	663.4	670.9	683.1	8034.5
7. RSH	63.0	51.0	1.0	37.0	4.0	0.0	0.0	0.0	7.0	37.0	5.0	16.0	221.0
8. UH	42.0	39.8	45.9	42.2	45.7	44.4	45.9	45.9	44.0	43.6	44.1	44.9	528.5
9. POH	0	0	0	0	0	0	0	0	0	0	0	0	0.0
10. FOH & EFOH	28.8	27.2	31.4	28.8	31.2	30.4	31.4	31.4	30.1	29.9	30.2	30.7	361.6
11. MOH & EMOH	39.1	37.1	42.7	39.2	42.5	41.4	42.7	42.7	41.0	40.6	41.1	41.8	491.9
12. Oper. Btu(MBtu)	1652955	1612493	2246556	1931247	2058794	2107090	2226424	2253904	2093909	2014791	1916346	1937530	24063727
13. Net Gen. (MWH)	165603.5	161945.6	229769.5	196155.3	208778.6	214761.9	227457.5	230569	213495.9	204799.9	193648.4	195662.7	2442647.8
14. ANOHR (Btu/KWH)	9981	9957	9777	9846	9861	9811	9788	9775	9808	9838	9896	9902	9851
15. NOF (%)	70.2	72.5	89.3	83.0	81.5	86.2	88.3	89.5	86.5	83.7	78.2	77.6	82.4
16. NSC (MW)	369	369	369	369	369	369	369	369	369	369	369	369	369
17. ANOHR Equation	ANOHR=	-10.689 x NOF +		10732.1									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT *Crystal River 2*	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Year*
1. EAF	89.31	88.20	48.33	0.00	59.91	87.93	87.86	87.81	87.90	88.16	88.41	88.85	75.25
2. POF	0.00	0.00	45.16	100.00	32.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.75
3. EUOF	10.69	11.80	6.51	0.00	7.83	12.07	12.14	12.19	12.10	11.84	11.59	11.15	9.99
4. EUOR	12.29	12.29	12.29	0.00	12.29	12.29	12.29	12.29	12.29	12.29	12.29	12.29	12.29
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	588.9	608.0	358.6	0.0	431.5	643.5	669.0	671.8	645.4	652.6	618.1	614.4	6501.9
7. RSH	97.0	28.0	14.0	0.0	30.0	13.0	9.0	6.0	11.0	27.0	41.0	69.0	345.0
8. UH	58.1	60.0	371.4	720.0	282.5	63.5	66.0	66.2	63.6	64.4	60.9	60.6	1937.1
9. POH	0	0	336	720	240	0	0	0	0	0	0	0	1296.0
10. FOH & EFOH	54.5	56.2	33.2	0.0	39.9	59.5	61.9	62.1	59.7	60.4	57.2	56.8	601.3
11. MOH & EMOH	25.0	25.9	15.3	0.0	18.4	27.4	28.5	28.6	27.5	27.8	26.3	26.1	276.6
12. Oper. Btu(MBtu)	1469717	1564761	1293780	0	1413204	2277715	2484257	2544218	2306451	2061557	2079622	1961783	21471815
13. Net Gen. (MWH)	148358.7	158059.5	131883.2	0	143427.8	231681.7	253062.4	259333.6	234673.1	209025.8	211221.7	198966.3	2179693.8
14. ANOHR (Btu/KWH)	9907	9900	9810	0	9853	9831	9817	9811	9828	9863	9846	9860	9851
15. NOF (%)	54.3	56.0	79.3	0.0	68.1	73.8	77.5	79.1	74.5	65.6	70.0	66.4	68.7
16. NSC (MW)	464	464	464	488	488	488	488	488	488	488	488	488	488
17. ANOHR *Equation*	ANOHR=	-3.865 x NOF +		10116.3									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Crystal River 3	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43	93.43
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57
4. EUOR	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57	6.57
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	711.5	665.6	711.5	688.5	711.5	688.5	711.5	711.5	688.5	711.5	688.5	711.5	8400.3
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0.0
8. UH	32.5	30.4	32.5	31.5	32.5	31.5	32.5	32.5	31.5	32.5	31.5	32.5	383.7
9. POH	0	0	0	0	0	0	0	0	0	0	0	0	0.0
10. FOH & EFOH	41.9	39.2	41.9	40.6	41.9	40.6	41.9	41.9	40.6	41.9	40.6	41.9	494.9
11. MOH & EMOH	7.0	6.5	7.0	6.7	7.0	6.7	7.0	7.0	6.7	7.0	6.7	7.0	82.1
12. Oper. Btu(MBtu)	5612822	5213737	5660506	5388478	5557240	5359864	5510005	5499222	5369729	5536831	5425820	5608737	65746199
13. Net Gen. (MWH)	544083	503612	551091	520250	536028	516138	529275	527745	517552	533100	525665	543487	6348026
14. ANOHR (Btu/KWH)	10316	10353	10271	10357	10367	10385	10410	10420	10375	10386	10322	10320	10357
15. NOF (%)	101.4	100.3	102.7	100.2	99.9	99.4	98.7	98.4	99.7	99.4	101.3	101.3	100.2
16. NSC (MW)	754	754	754	754	754	754	754	754	754	754	754	754	754
17. ANOHR Equation	ANOHR=	-34.186 x NOF +		13783.3									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Crystal River 4	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	91.38	91.37	8.84	0.00	76.68	91.39	91.37	91.37	91.37	91.40	91.37	91.37	75.65
2. POF	0.00	0.00	90.32	100.00	16.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.21
3. EUOF	8.62	8.63	0.84	0.00	7.20	8.61	8.63	8.63	8.63	8.60	8.63	8.63	7.14
4. EUOR	8.63	8.63	8.63	0.00	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	699.5	655.3	67.8	0.0	583.7	676.0	700.5	700.5	677.9	697.6	677.9	700.5	6837.0
7. RSH	1.0	0.0	0.0	0.0	4.0	2.0	0.0	0.0	0.0	3.0	0.0	0.0	10.0
8. UH	43.5	40.7	676.2	720.0	156.3	42.0	43.5	43.5	42.1	43.4	42.1	43.5	1937.0
9. POH	0.0	0.0	672.0	720.0	120.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1512.0
10. FOH & EFOH	43.3	40.6	4.2	0.0	36.1	41.8	43.4	43.4	42.0	43.2	42.0	43.4	423.3
11. MOH & EMOH	20.8	19.5	2.0	0.0	17.4	20.1	20.9	20.9	20.2	20.8	20.2	20.9	203.8
12. Oper. Btu(MBtu)	3502306	3586162	322927	0	3375860	4159742	4539108	4502565	4401641	4300303	4161928	4313502	41199770
13. Net Gen. (MWH)	367262.3	378458.1	33752.6	0.0	357118.5	442277.3	484807.2	480553.6	470211.7	457288.3	442425.1	458653.8	4372808.5
14. ANOHR (Btu/KWH)	9536	9476	9567	0	9453	9405	9363	9370	9361	9404	9407	9405	9422
15. NOF (%)	75.3	82.9	71.4	0.0	85.7	91.6	96.9	96.1	97.2	91.8	91.4	91.7	89.6
16. NSC (MW)	697	697	697	714	714	714	714	714	714	714	714	714	714
17. ANOHR Equation	ANOHR=	-8.030 x NOF +		10141.2									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Crystal River 5	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.85	95.89	95.88	95.85	95.85	95.88	95.88	95.85	95.87	95.85	73.49	95.98	94.04
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.33	0.00	1.91
3. EUOF	4.15	4.11	4.12	4.15	4.15	4.12	4.12	4.15	4.13	4.15	3.18	4.02	4.05
4. EUOR	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15	4.15
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	730.5	676.5	725.6	706.9	730.5	702.0	725.6	730.5	703.0	730.5	541.0	706.9	8409.2
7. RSH	0.0	7.0	5.0	0.0	0.0	5.0	5.0	0.0	4.0	0.0	1.0	24.0	51.0
8. UH	13.5	12.5	13.4	13.1	13.5	13.0	13.4	13.5	13.0	13.5	178.0	13.1	323.8
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	168.0	0.0	168.0
10. FOH & EFOH	21.6	20.0	21.5	20.9	21.6	20.8	21.5	21.6	20.8	21.6	16.0	20.9	248.6
11. MOH & EMOH	9.3	8.6	9.2	9.0	9.3	8.9	9.2	9.3	8.9	9.3	6.9	9.0	107.0
12. Oper. Btu(MBtu)	4721985	4489186	4767915	4356365	4129051	4137542	4445191	4567698	4246837	4251212	3162193	4298556	51580673
13. Net Gen. (MWH)	504174.7	480064.4	509571.6	463877.1	437683.9	439522.3	473183.1	486775.1	451724.2	451300.2	335768.0	457387.0	5491031.6
14. ANOHR (Btu/KWH)	9366	9351	9357	9391	9434	9414	9394	9384	9401	9420	9418	9398	9394
15. NOF (%)	96.7	99.4	98.4	91.9	83.9	87.7	91.3	93.3	90.0	86.5	86.9	90.6	91.5
16. NSC (MW)	714	714	714	714	714	714	714	714	714	714	714	714	714
17. ANOHR Equation	ANOHR=	-5.341 x NOF +		9882.1									

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ESTIMATED UNIT PERFORMANCE DATA
Florida Power Corporation

Period of: January, 2000-December, 2000

PLANT/UNIT Tiger Bay	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.23	95.65	9.22	49.66	92.54	91.79	91.68	91.25	91.53	82.16	63.85	94.43	79.13
2. POF	0.00	0.00	90.32	46.67	0.00	0.00	0.00	0.00	0.00	12.90	33.33	0.00	15.30
3. EUOF	3.77	4.35	0.46	3.68	7.46	8.21	8.32	8.75	8.47	4.93	2.82	5.57	5.57
4. EUOR	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	276.2	298.0	33.6	260.8	547.0	582.4	609.7	641.5	600.6	361.6	199.9	408.0	4819.4
7. RSH	440.0	368.0	35.0	97.0	142.0	79.0	73.0	38.0	59.0	250.0	260.0	295.0	2136.0
8. UH	27.8	30.0	675.4	362.2	55.0	58.6	61.3	64.5	60.4	132.4	260.1	41.0	1828.6
9. POH	0.0	0.0	672.0	336.0	0.0	0.0	0.0	0.0	0.0	96.0	240.0	0.0	1344 0
10. FOH & EFOH	17.6	18.9	2.1	16.6	34.8	37.0	38.7	40.8	38.2	23.0	12.7	25.9	306.3
11. MOH & EMOH	10.5	11.3	1.3	9.9	20.8	22.1	23.2	24.4	22.8	13.7	7.6	15.5	183.0
12. Oper. Btu(MBtu)	355408	412427	41952	383785	763363	833650	861995	916354	842125	500150	279313	575052	6780145
13. Net Gen. (MWH)	42655.6	53169.5	4920.9	55023.7	99473.2	112796.9	114383.7	123573.6	110431.9	64431.7	36456.4	75969.1	893286.2
14. ANOHR (Btu/KWH)	8332	7757	8525	6975	7674	7391	7536	7415	7626	7762	7662	7570	7590
15. NOF (%)	75.0	86.6	71.1	102.4	88.3	94.0	91.1	93.5	89.3	86.5	88.5	90.4	90.0
16. NSC (MW)	206	206	206	206	206	206	206	206	206	206	206	206	206
17. ANOHR Equation	ANOHR=	-49.416 x NOF +		12036.4									

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Order No.:

PLANNED OUTAGE SCHEDULES

Company: Florida Power Corporation
Period of: January 2000 - December 2000

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 1	02/19 (0001) - 02/25 (2400)	Inspection
Anclote 1	09/30 (0001) - 10/06 (2400)	Inspection
Anclote 2	02/26 (0001) - 03/03 (2400)	Inspection
Anclote 2	10/28 (0001) - 11/24 (2400)	Boiler
Bartow 3	02/26 (0001) - 03/24 (2400)	Boiler
Bartow 3	12/02 (0001) - 12/08 (2400)	Inspection
Crystal River 2	03/18 (0001) - 05/10 (2400)	Boiler/Turb./Gen.
Crystal River 4	03/04 (0001) - 05/05 (2400)	Boiler/HP Turbine Upgrade/Condenser Coating
Crystal River 5	11/04 (0001) - 11/10 (2400)	Inspection
Tiger Bay	03/04 (0001) - 04/14 (2400)	Stm. Turb./Gen. Field/Comb. Insp./HRSG
Tiger Bay	10/28 (0001) - 11/10 (2400)	Cycle Off

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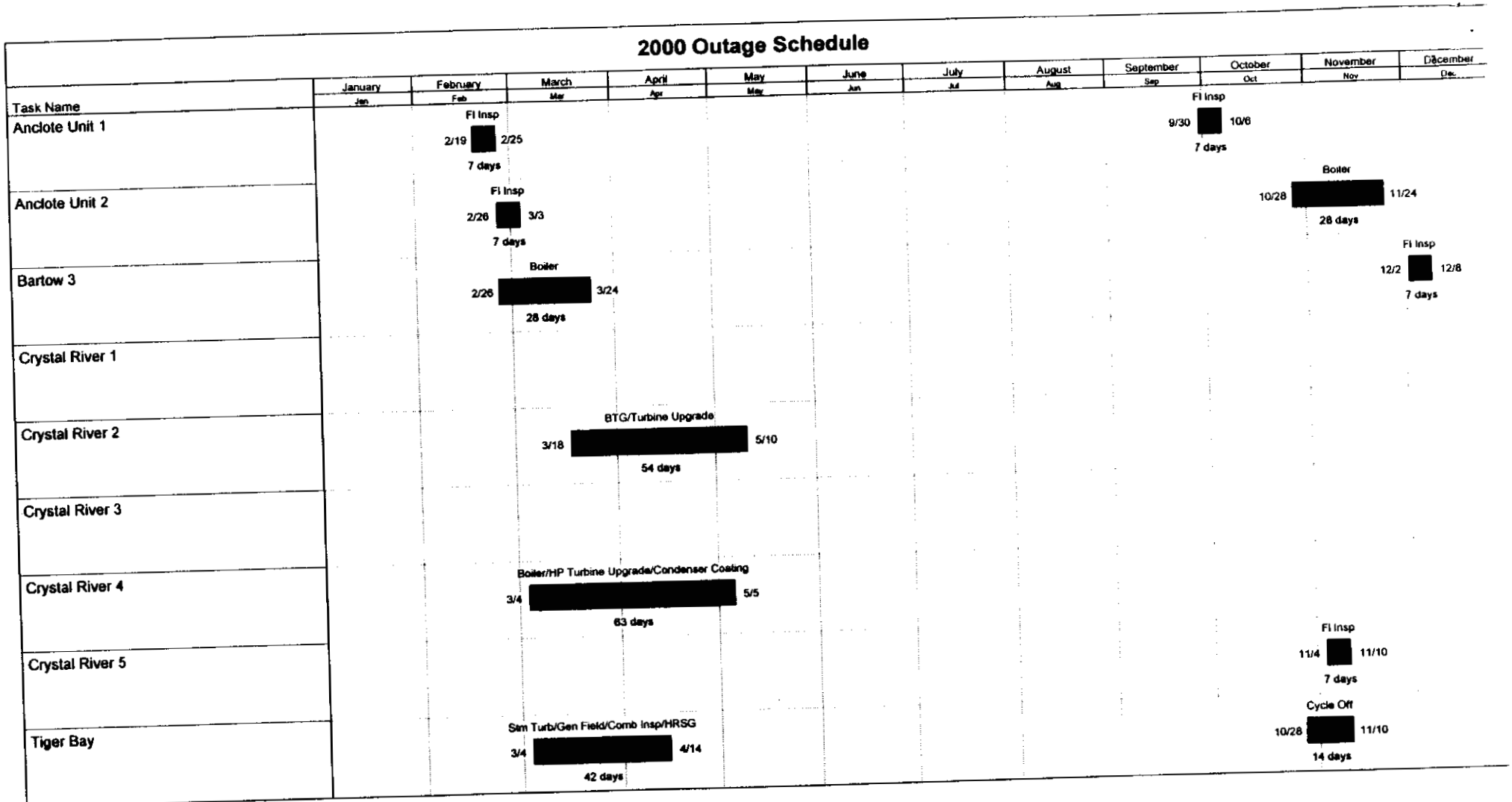
2000 Outage Schedule



Florida Power Corporation

AVERAGE NET OPERATING

HEAT RATE CURVES

FLORIDA POWER CORPORATION

ANCLOTE 1

ANOHR -9.610 * NOF + 10521.91

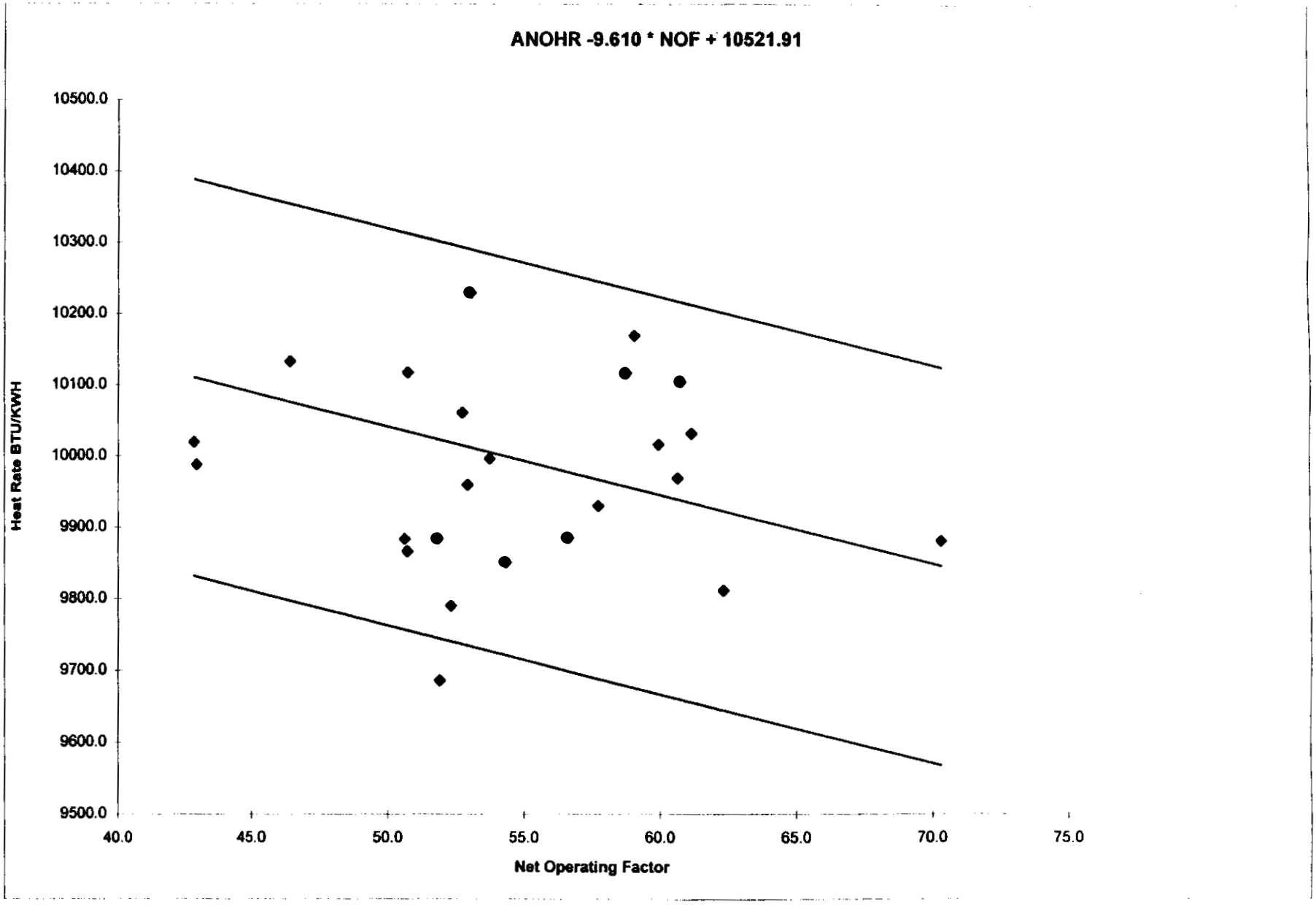
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	54.3	9851.7	10000.1	-148.4	278.4
Jul-96	59.9	10016.9	9946.3	70.6	278.4
Aug-96	52.7	10061.7	10015.5	46.2	278.4
Sep-96	57.7	9930.9	9967.4	-36.5	278.4
Oct-96	56.6	9886.1	9978.0	-91.9	278.4
Nov-96	59.0	10169.9	9954.9	215.0	278.4
Dec-96	50.7	9866.9	10034.7	-167.8	278.4
Jan-97	51.9	9686.5	10023.2	-336.7	278.4
Feb-97	42.9	9988.2	10109.7	-121.5	278.4
Mar-97	53.7	9997.1	10005.9	-8.8	278.4
Apr-97	50.6	9883.9	10035.7	-151.8	278.4
May-97	46.4	10133.5	10076.0	57.5	278.4
Jun-97	53.0	10229.9	10012.6	217.3	278.4
Jul-97	60.7	10104.8	9938.6	166.2	278.4
Aug-97	61.1	10032.6	9934.8	97.8	278.4
Sep-97	60.6	9969.5	9939.6	29.9	278.4
Oct-97	50.7	10117.9	10034.7	83.2	278.4
Dec-97	52.3	9790.9	10019.3	-228.4	278.4
Jan-98	42.8	10020.0	10110.6	-90.6	278.4
Feb-98	51.8	9884.8	10024.1	-139.3	278.4
Mar-98	62.3	9813.0	9923.2	-110.2	278.4
Apr-98	52.9	9959.9	10013.6	-53.7	278.4
May-98	58.7	10117.2	9957.8	159.4	278.4
Jun-98	70.3	9881.7	9846.3	35.4	278.4
Jul-98	68.6	10010.8	9862.7	148.1	278.4
Aug-98	66.2	9758.6	9885.7	-127.1	278.4
Sep-98	58.7	10224.7	9957.8	266.9	278.4
Oct-98	51.2	10103.3	10029.9	73.4	278.4
Nov-98	64.7	9703.2	9900.2	-197.0	278.4
Dec-98	75.9	9630.3	9792.5	-162.2	278.4
Jan-99	61.0	10074.0	9935.7	138.3	278.4
Feb-99	73.6	9780.5	9814.6	-34.1	278.4
Mar-99	63.7	9618.8	9909.8	-291.0	278.4
May-99	55.9	10094.9	9984.7	110.1	278.4
Jun-99	51.4	10461.3	10028.0	433.3	278.4

Regression Output:

Constant	10521.91
Std Err of Y Est	171.773282
R Squared	0.168485898
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-9.609697134
Std Err of Coef.	3.773877001

Anclote Unit 1



FLORIDA POWER CORPORATION

ANCLOTE UNIT 2

ANOHR -13.676 * NOF + 10752.48

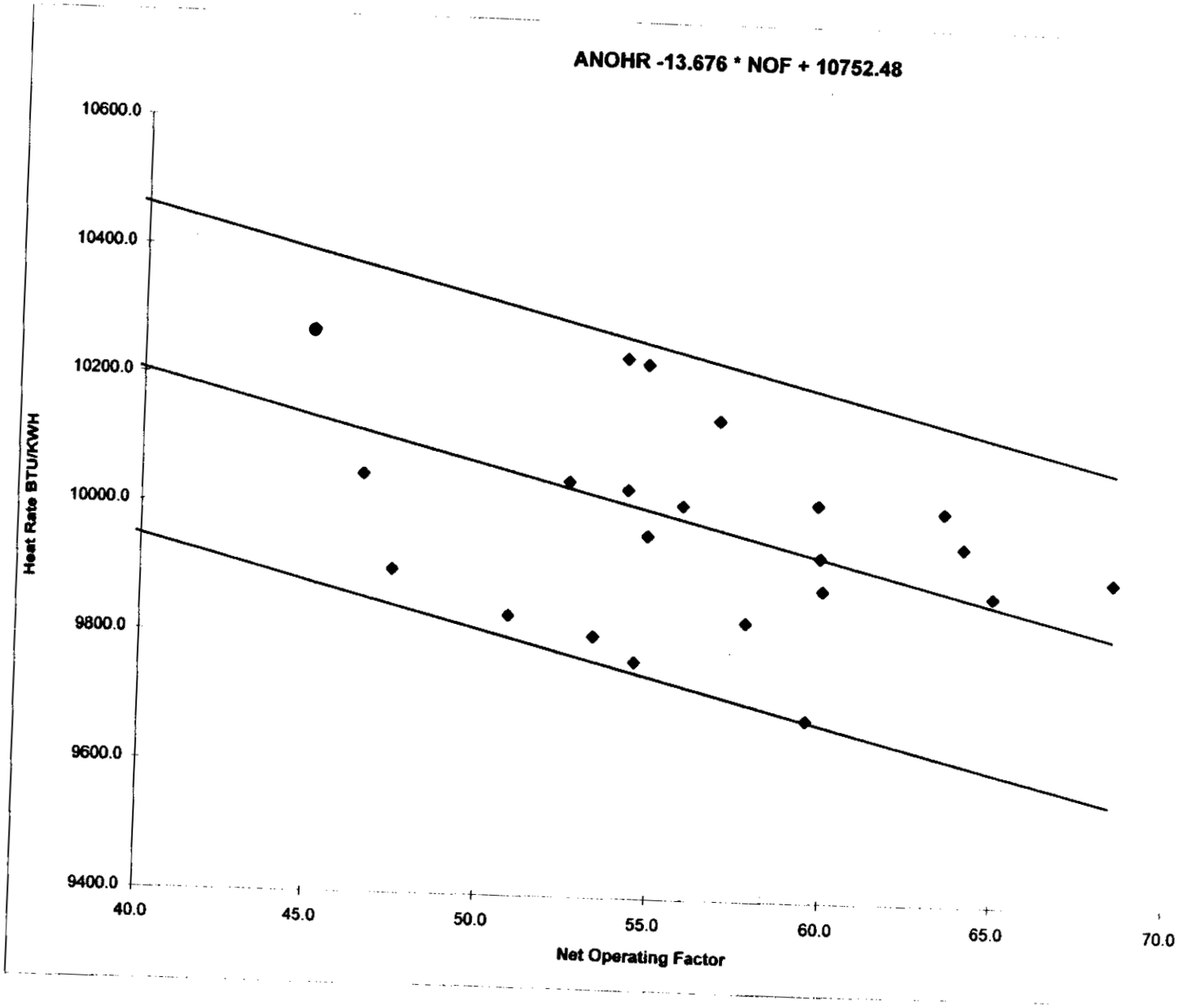
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	59.5	9683.2	9938.7	-255.5	258.0
Jul-96	59.8	9935.7	9934.6	1.1	258.0
Aug-96	54.1	10238.5	10012.6	225.9	258.0
Sep-96	59.7	10017.8	9936.0	81.8	258.0
Oct-96	56.8	10145.3	9975.7	169.6	258.0
Jan-97	54.2	10034.2	10011.2	23.0	258.0
Feb-97	50.8	9834.1	10057.7	-223.6	258.0
Mar-97	57.7	9831.9	9963.4	-131.5	258.0
Apr-97	53.3	9804.8	10023.5	-218.7	258.0
May-97	45.0	10271.4	10137.0	134.4	258.0
Jun-97	54.7	10230.5	10004.4	226.1	258.0
Jul-97	63.4	10009.5	9885.4	124.1	258.0
Aug-97	64.0	9954.9	9877.2	77.7	258.0
Sep-97	64.9	9878.9	9864.9	14.0	258.0
Oct-97	52.5	10044.4	10034.5	9.9	258.0
Nov-97	46.5	10048.7	10116.5	-67.8	258.0
Dec-97	54.5	9766.8	10007.1	-240.3	258.0
Jan-98	39.5	10222.9	10212.3	10.6	258.0
Feb-98	47.4	9901.3	10104.2	-202.9	258.0
Mar-98	54.8	9962.9	10003.0	-40.1	258.0
Apr-98	55.8	10011.4	9989.3	22.1	258.0
May-98	59.9	9884.6	9933.3	-48.7	258.0
Jun-98	68.4	9905.3	9817.0	88.3	258.0
Jul-98	68.0	9909.5	9822.5	87.0	258.0
Aug-98	66.5	10227.9	9843.0	384.9	258.0
Sep-98	57.2	9982.5	9970.2	12.3	258.0
Oct-98	60.8	9928.6	9921.5	7.1	258.0
Nov-98	0.0	0.0	10752.5	-10752.5	258.0
Dec-98	80.0	9510.5	9658.7	-148.2	258.0
Jan-99	62.6	9682.3	9896.3	-214.0	258.0
Feb-99	66.0	9580.4	9849.8	-269.4	258.0
Mar-99	63.4	9832.5	9885.4	-52.9	258.0
Apr-99	70.1	9807.5	9793.8	13.7	258.0
May-99	54.0	9902.6	10014.0	-111.4	258.0
Jun-99	46.7	10369.9	10113.8	256.1	258.0

Regression Output:

Constant	10752.48
Std Err of Y Est	159.2556978
R Squared	0.346429523
No. of Observations	33
Degrees of Freedom	32
X Coefficient	-13.6762612
Std Err of Coef.	3.373846392

Anclote Unit 2



FLORIDA POWER CORPORATION

BARTOW UNIT 3

ANOHR -12.673 * NOF + 10914.03

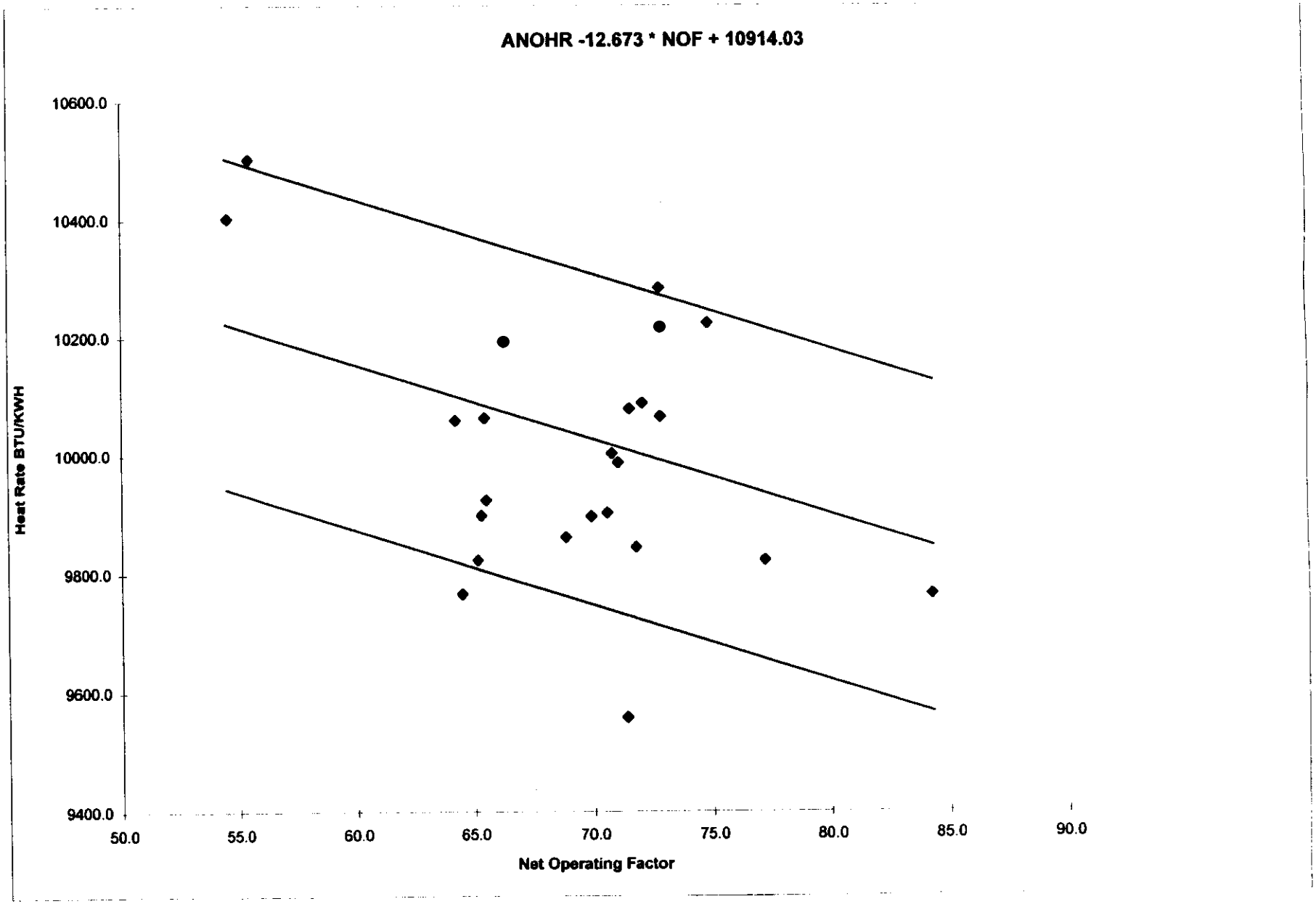
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	70.5	9903.0	10020.1	-117.1	280.0
Jul-96	55.5	10503.0	10211.2	291.8	280.0
Aug-96	72.8	10066.0	9991.8	74.2	280.0
Sep-96	74.8	10224.0	9966.7	257.3	280.0
Oct-96	70.7	10003.0	10017.5	-14.5	280.0
Nov-96	71.0	9988.0	10014.2	-26.2	280.0
Dec-96	68.8	9862.0	10041.9	-179.9	280.0
Jan-97	64.2	10060.0	10100.9	-40.9	280.0
Feb-97	65.4	10064.0	10084.9	-20.9	280.0
Mar-97	72.7	10284.0	9992.2	291.8	280.0
Apr-97	65.5	9925.0	10084.1	-159.1	280.0
May-97	69.9	9897.0	10028.5	-131.5	280.0
Jun-97	72.8	10217.0	9991.7	225.3	280.0
Jul-97	71.5	10079.0	10008.3	70.7	280.0
Aug-97	66.3	10193.0	10074.4	118.6	280.0
Sep-97	72.0	10089.0	10001.3	87.7	280.0
Oct-97	54.5	10403.0	10222.8	180.2	280.0
Nov-97	65.1	9824.0	10088.7	-264.7	280.0
Dec-97	71.4	9559.0	10009.7	-450.7	280.0
Jan-98	64.5	9767.0	10097.2	-330.2	280.0
Feb-98	65.3	9899.0	10086.7	-187.7	280.0
Mar-98	84.2	9764.0	9846.4	-82.4	280.0
Apr-98	71.7	9845.0	10004.8	-159.8	280.0
May-98	77.2	9823.0	9936.2	-113.2	280.0
Jun-98	85.7	9838.0	9828.1	9.9	280.0
Jul-98	81.7	9981.0	9878.1	102.9	280.0
Aug-98	83.0	9825.0	9862.3	-37.3	280.0
Sep-98	78.9	9892.0	9914.4	-22.4	280.0
Oct-98	73.8	10099.0	9978.7	120.3	280.0
Nov-98	74.5	9937.0	9970.3	-33.3	280.0
Dec-98	89.7	9692.0	9777.4	-85.4	280.0
Jan-99	85.9	9749.0	9825.6	-76.6	280.0
Feb-99	92.6	9818.0	9740.2	77.8	280.0
Mar-99	78.7	9984.0	9916.4	67.6	280.0
Apr-99	80.5	10042.0	9894.0	148.0	280.0
May-99	69.5	10223.0	10033.7	189.3	280.0
Jun-99	70.7	10122.0	10018.7	103.3	280.0

Regression Output:

Constant	10914.03
Std Err of Y Est	172.6061632
R Squared	0.290465777
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-12.6733063
Std Err of Coef.	3.396953969

Bartow Unit 3



FLORIDA POWER CORPORATION

CRYSTAL RIVER 1

ANOHR -10.689 * NOF + 10732.14

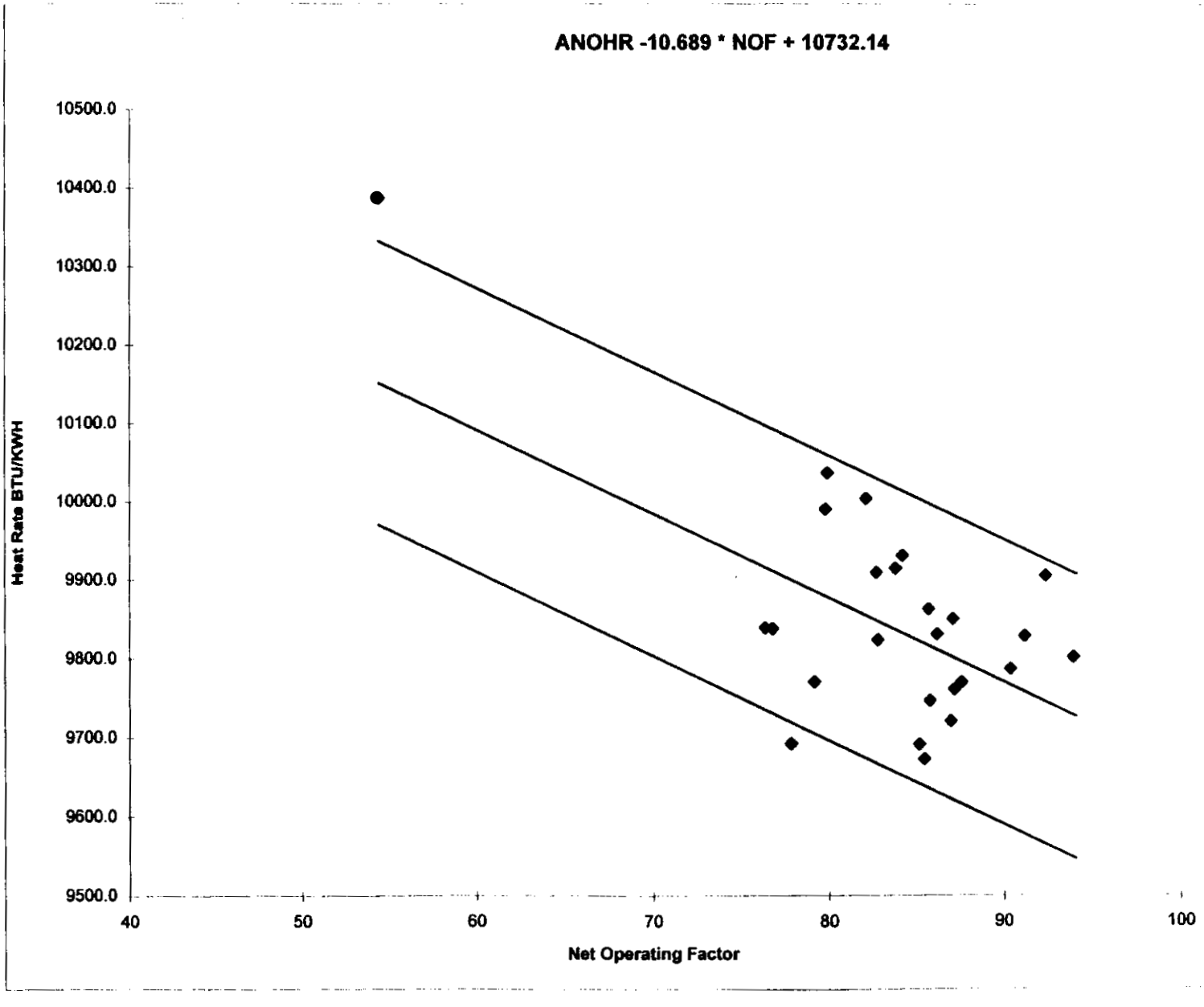
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	84.1	9932.0	9833.2	98.8	180.8
Jul-96	82.6	9910.1	9849.2	60.9	180.8
Aug-96	79.7	9991.3	9880.2	111.1	180.8
Sep-96	83.7	9915.4	9837.5	77.9	180.8
Oct-96	79.8	10037.3	9879.2	158.1	180.8
Nov-96	54.3	10387.8	10151.7	236.1	180.8
Dec-96	76.7	9839.1	9912.3	-73.2	180.8
Jan-97	79.1	9771.5	9886.7	-115.2	180.8
Feb-97	85.1	9691.9	9822.5	-130.6	180.8
Mar-97	85.6	9863.8	9817.2	46.6	180.8
Apr-97	90.3	9787.4	9766.9	20.5	180.8
May-97	87.5	9770.8	9796.9	-26.1	180.8
Jun-97	86.1	9832.0	9811.8	20.2	180.8
Jul-97	87.0	9851.3	9802.2	49.1	180.8
Aug-97	92.3	9906.1	9745.6	160.5	180.8
Sep-97	91.1	9829.4	9758.4	71.0	180.8
Oct-97	86.9	9721.4	9803.3	-81.9	180.8
Nov-97	82.7	9824.7	9848.2	-23.5	180.8
Dec-97	87.1	9761.7	9801.1	-39.4	180.8
Jan-98	85.4	9673.4	9819.3	-145.9	180.8
Feb-98	76.3	9840.0	9916.6	-76.6	180.8
Mar-98	77.8	9693.3	9900.6	-207.3	180.8
Apr-98	93.9	9802.3	9728.5	73.8	180.8
May-98	85.7	9747.3	9816.1	-68.8	180.8
Jun-98	82.0	10004.5	9855.7	148.8	180.8
Jul-98	73.7	10056	9944.4	111.6	180.8
Aug-98	89.5	9918	9775.5	142.5	180.8
Sep-98	83.1	9772.1	9843.9	-71.8	180.8
Oct-98	88.1	9772.9	9790.5	-17.6	180.8
Nov-98	75.0	9740.3	9930.5	-190.2	180.8
Dec-98	73.4	9830.3	9947.6	-117.3	180.8
Jan-99	66.3	9879.2	10023.5	-144.3	180.8
Feb-99	55.9	10257.6	10134.6	123.0	180.8
Mar-99	77.4	9848.6	9904.8	-56.2	180.8
Apr-99	87.5	9861.8	9796.9	64.9	180.8
May-99	65.1	9992	10036.3	-44.3	180.8
Jun-99	75.5	9878.7	9925.1	-46.4	180.8

Regression Output:

Constant	10732.14
Std Err of Y Est	111.4437779
R Squared	0.44634629
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-10.68873218
Std Err of Coef.	2.041596345

Crystal River Unit 1



FLORIDA POWER CORPORATION

CRYSTAL RIVER 2

ANOHR -3.865 * NOF + 10116.34

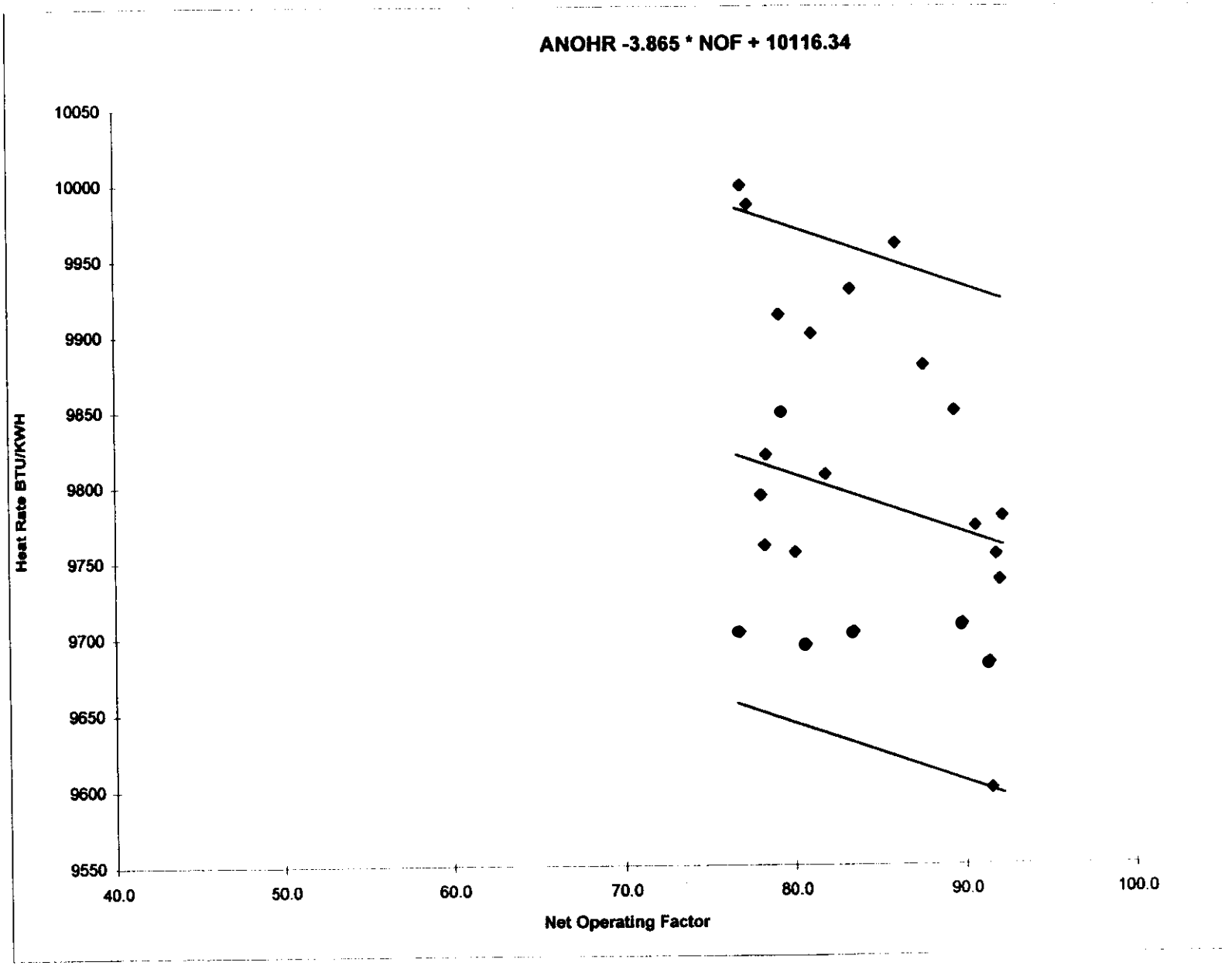
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	81.0	9900.9	9803.3	97.6	163.6
Jul-96	79.1	9913.3	9810.6	102.7	163.6
Aug-96	76.9	9999.0	9819.1	179.9	163.6
Sep-96	83.3	9930.2	9794.4	135.8	163.6
Oct-96	77.3	9986.5	9817.6	168.9	163.6
Nov-96	80.0	9756.1	9807.2	-51.1	163.6
Dec-96	78.0	9794.0	9814.9	-20.9	163.6
Jan-97	78.2	9760.6	9814.1	-53.5	163.6
Feb-97	91.5	9600.1	9762.7	-162.6	163.6
Apr-97	92.0	9737.2	9760.8	-23.6	163.6
May-97	83.4	9703.5	9794.0	-90.5	163.6
Jun-97	90.6	9772.9	9766.2	6.7	163.6
Jul-97	92.2	9779.4	9760.0	19.4	163.6
Aug-97	89.4	9849.4	9770.8	78.6	163.6
Sep-97	91.8	9754.2	9761.6	-7.4	163.6
Oct-97	89.8	9708.6	9769.3	-60.7	163.6
Nov-97	79.2	9848.9	9810.2	38.7	163.6
Dec-97	87.6	9879.7	9777.8	101.9	163.6
Jan-98	76.7	9703.6	9819.9	-116.3	163.6
Feb-98	78.3	9820.6	9813.7	6.9	163.6
Mar-98	91.4	9683.0	9763.1	-80.1	163.6
Apr-98	80.6	9695.1	9804.8	-109.7	163.6
May-98	81.8	9807.3	9800.2	7.1	163.6
Jun-98	86.0	9960.6	9784.0	176.6	163.6
Jul-98	98.1	9732.3	9737.2	-4.9	163.6
Aug-98	98.0	9809.2	9737.6	71.6	163.6
Sep-98	88.4	9708.8	9774.7	-65.9	163.6
Oct-98	71.8	9767.8	9838.8	-71.0	163.6
Nov-98	73.5	9729.1	9832.3	-103.2	163.6
Dec-98	66.8	9812.3	9858.2	-45.9	163.6
Jan-99	62.4	9767.0	9875.2	-108.2	163.6
Feb-99	54.5	10053.1	9905.7	147.4	163.6
Mar-99	76.4	9678.6	9821.1	-142.5	163.6
Apr-99	94.7	9635.0	9750.3	-115.3	163.6
May-99	90.8	9920.5	9765.4	155.1	163.6
Jun-99	87.3	9815.0	9778.9	36.1	163.6

Regression Output:

Constant	10116.34
Std Err of Y Est	100.9237975
R Squared	0.125917923
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-3.864759824
Std Err of Coef.	1.772547459

Crystal River Unit 2



FLORIDA POWER CORPORATION

CRYSTAL RIVER 3

ANOHR -34.186 * NOF + 13783.25

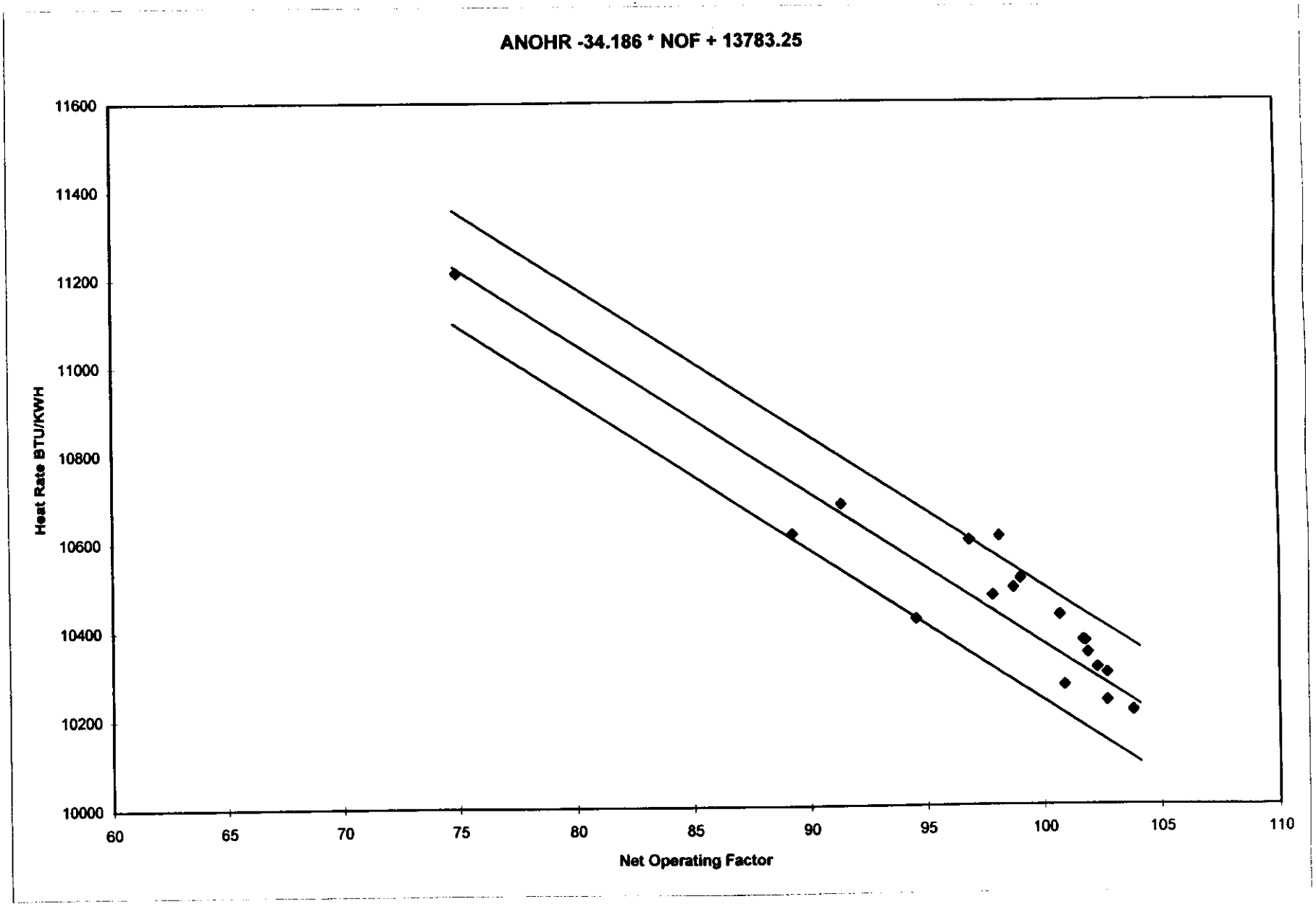
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	CT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-95	100.7	10429.3	10340.7	88.6	128.9
Jul-95	99.0	10512.0	10398.8	113.2	128.9
Aug-95	98.1	10608.4	10429.6	178.8	128.9
Sep-95	97.8	10473.9	10439.8	34.1	128.9
Oct-95	98.7	10491.4	10409.1	82.3	128.9
Nov-95	102.3	10308.5	10286.0	22.5	128.9
Dec-95	102.7	10296.4	10272.3	24.1	128.9
Jan-96	96.8	10600.0	10474.0	126.0	128.9
Feb-96	101.9	10342.3	10299.7	42.6	128.9
May-96	74.9	11213.7	11222.7	-9.0	128.9
Jun-96	91.3	10683.6	10662.1	21.5	128.9
Jul-96	101.7	10371.2	10306.5	64.7	128.9
Aug-96	94.5	10422.2	10552.7	-130.5	128.9
Feb-98	89.2	10616.3	10733.8	-117.5	128.9
Mar-98	103.8	10212.5	10234.7	-22.2	128.9
Apr-98	100.9	10269.6	10333.9	-64.3	128.9
May-98	102.7	10234.6	10272.3	-37.7	128.9
Jun-98	101.8	10369.0	10303.1	65.9	128.9
Jul-98	99.7	10405.5	10374.9	30.6	128.9
Aug-98	100.7	10419.5	10340.7	78.8	128.9
Sep-98	102.7	10280.6	10272.3	8.3	128.9
Oct-98	103.26	10209.4	10253.2	-43.8	128.9
Nov-98	103.22	10177.3	10254.6	-77.3	128.9
Dec-98	103.68	10179.2	10238.8	-59.6	128.9
Jan-99	104	10198.0	10227.9	-29.9	128.9
Feb-99	101.6	10166.1	10309.9	-143.8	128.9
Mar-99	104.2	10165.7	10221.0	-55.3	128.9
Apr-99	100.2	10259.0	10357.8	-98.8	128.9
May-99	102.3	10258.5	10286.0	-27.5	128.9
Jun-99	101.6	10333.8	10309.9	23.9	128.9

Regression Output:

Constant	13783.25
Std Err of Y Est	79.77542796
R Squared	0.871575892
No. of Observations	29
Degrees of Freedom	28
X Coefficient	-34.18618792
Std Err of Coef.	2.525454035

Crystal River Unit 3



FLORIDA POWER CORPORATION

CRYSTAL RIVER 4

ANOHR -8.030 * NOF + 10141.16

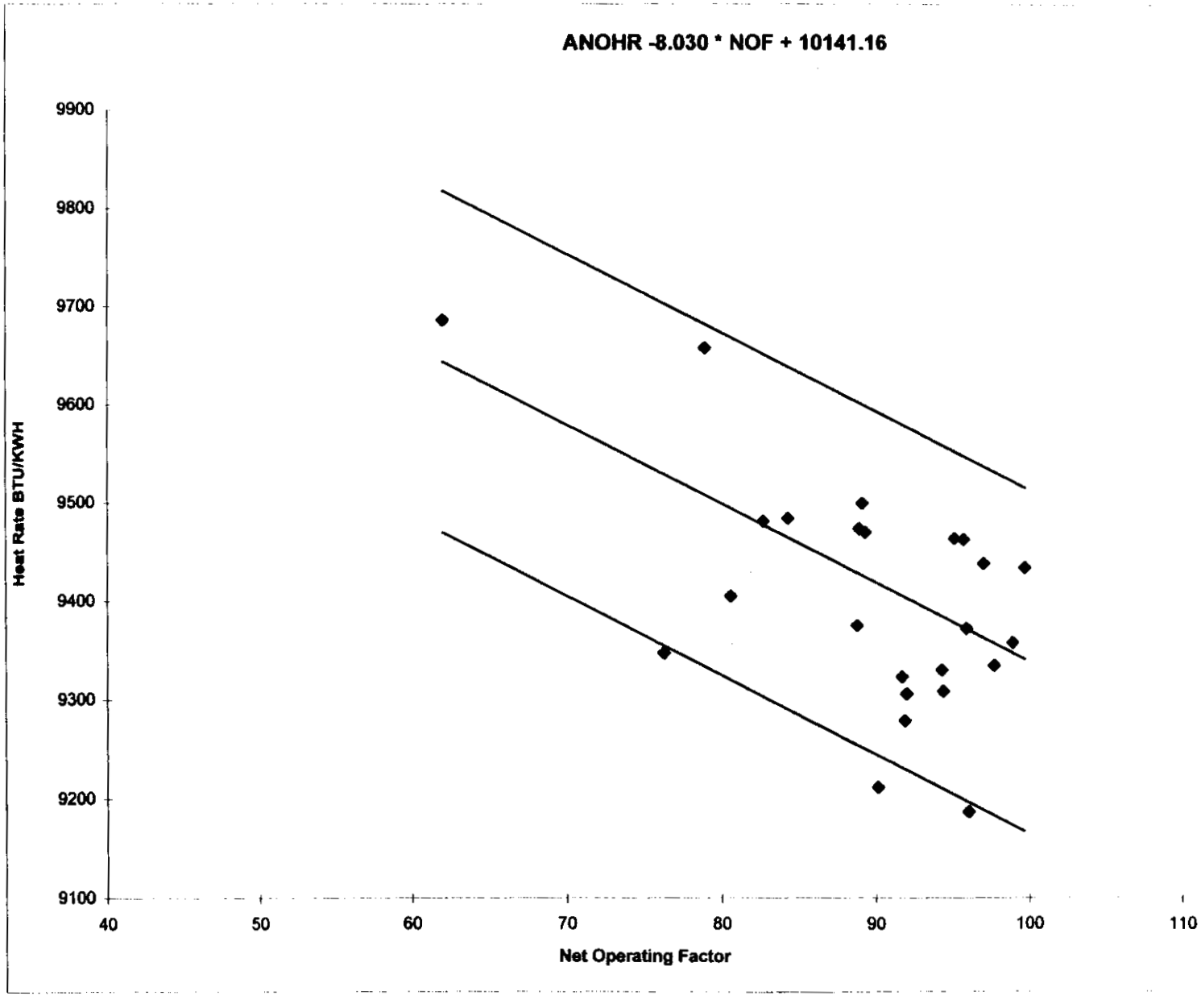
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	CT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	61.9	9686.6	9644.1	42.5	174.0
Jul-96	80.5	9405.7	9494.7	-89.0	174.0
Aug-96	84.2	9484.8	9465.0	19.8	174.0
Sep-96	94.3	9308.8	9383.9	-75.1	174.0
Oct-96	94.2	9330.4	9384.7	-54.3	174.0
Nov-96	90.1	9211.7	9417.6	-205.9	174.0
Dec-96	91.6	9323.7	9405.6	-81.9	174.0
Jan-97	91.8	9279.0	9404.0	-125.0	174.0
Mar-97	96.0	9187.0	9370.2	-183.2	174.0
Apr-97	96.9	9438.5	9363.0	75.5	174.0
May-97	97.6	9335.2	9357.4	-22.2	174.0
Jun-97	95.6	9462.7	9373.4	89.3	174.0
Jul-97	99.6	9434.1	9341.3	92.8	174.0
Aug-97	95.0	9463.8	9378.3	85.5	174.0
Sep-97	89.0	9500.0	9426.4	73.6	174.0
Oct-97	95.8	9372.5	9371.8	0.7	174.0
Nov-97	88.7	9375.8	9428.9	-53.1	174.0
Dec-97	82.6	9481.7	9477.8	3.9	174.0
Jan-98	88.8	9474.1	9428.1	46.0	174.0
Feb-98	89.2	9470.4	9424.8	45.6	174.0
Mar-98	76.2	9348.0	9529.2	-181.2	174.0
Apr-98	78.8	9658.2	9508.4	149.8	174.0
May-98	91.9	9306.4	9403.2	-96.8	174.0
Jun-98	98.8	9358.1	9347.7	10.4	174.0
Jul-98	98.4	9385.7	9351.0	34.7	174.0
Aug-98	98	9464.7	9354.2	110.5	174.0
Sep-98	92.6	9481.7	9397.5	84.2	174.0
Oct-98	89.89	9363.2	9419.3	-56.1	174.0
Nov-98	80.85	9512	9491.9	20.1	174.0
Dec-98	71.41	9611.2	9567.7	43.5	174.0
Jan-99	74.8	9759.2	9540.5	218.7	174.0
Feb-99	66.2	9531.4	9609.5	-78.1	174.0
Mar-99	85.5	9260.3	9454.6	-194.3	174.0
Apr-99	98.7	9358.5	9348.6	9.9	174.0
May-99	84.1	9595.2	9465.8	129.4	174.0
Jun-99	85.9	9603.6	9451.3	152.3	174.0

Regression Output:

Constant	10141.16
Std Err of Y Est	107.327716
R Squared	0.291354107
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-8.030442201
Std Err of Coef.	2.180150906

Crystal River Unit 4



FLORIDA POWER CORPORATION

CRYSTAL RIVER 5

ANOHR -5.341 * NOF + 9882.10

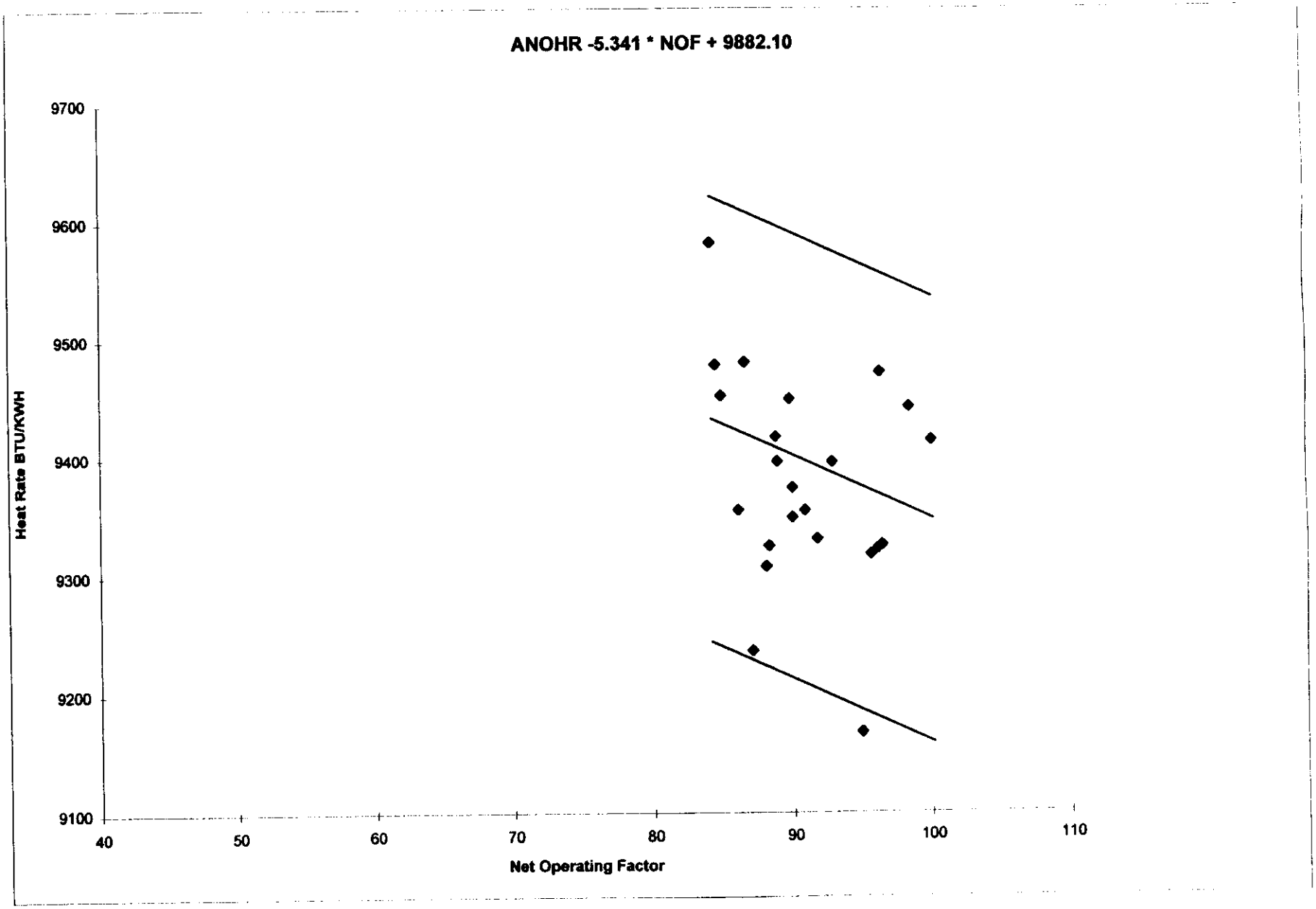
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jun-96	84.8	9452.4	9429.2	23.2	188.8
Jul-96	88.8	9396.5	9407.8	-11.3	188.8
Aug-96	84.4	9478.8	9431.3	47.5	188.8
Sep-96	89.9	9374.2	9401.9	-27.7	188.8
Oct-96	90.8	9355.0	9397.1	-42.1	188.8
Nov-96	87.0	9236.5	9417.4	-180.9	188.8
Dec-96	89.9	9349.0	9401.9	-52.9	188.8
Jan-97	88.0	9307.7	9412.1	-104.4	188.8
Feb-97	95.6	9317.9	9371.5	-53.6	188.8
Mar-97	94.9	9167.7	9375.2	-207.5	188.8
May-97	86.0	9355.3	9422.8	-67.5	188.8
Jun-97	98.4	9442.7	9356.5	86.2	188.8
Jul-97	100.0	9414.2	9348.0	66.2	188.8
Sep-97	89.7	9449.5	9403.0	46.5	188.8
Oct-97	96.1	9322.7	9368.8	-46.1	188.8
Nov-97	96.4	9325.4	9367.2	-41.8	188.8
Dec-97	91.7	9331.0	9392.3	-61.3	188.8
Jan-98	92.8	9395.9	9386.4	9.5	188.8
Feb-98	86.5	9480.9	9420.1	60.8	188.8
Mar-98	88.2	9325.1	9411.0	-85.9	188.8
Apr-98	84.1	9582.6	9432.9	149.7	188.8
May-98	88.7	9417.5	9408.3	9.2	188.8
Jun-98	96.3	9472.2	9367.7	104.5	188.8
Jul-98	94.6	9482.6	9376.8	105.8	188.8
Aug-98	95.4	9489.6	9372.5	117.1	188.8
Sep-98	89.5	9401.2	9404.1	-2.9	188.8
Oct-98	89	9319.9	9406.7	-86.8	188.8
Nov-98	81.7	9405.8	9445.7	-39.9	188.8
Dec-98	66.5	9561.1	9526.9	34.2	188.8
Jan-99	76.2	9393.5	9475.1	-81.6	188.8
Feb-99	65.7	9540.5	9531.2	9.3	188.8
Mar-99	76.8	9355.7	9471.9	-116.2	188.8
Apr-99	0	0	9882.1	-9882.1	188.8
May-99	83.2	9882	9437.7	444.3	188.8
Jun-99	88.8	9427.5	9407.8	19.7	188.8
Jul-99	90.75	9315			
Aug-99	97.3	9262			

Regression Output:

Constant	9882.10
Std Err of Y Est	116.5698313
R Squared	0.121455929
No. of Observations	33
Degrees of Freedom	32
X Coefficient	-5.341268432
Std Err of Coef.	2.580096643

Crystal River Unit 5



FLORIDA POWER CORPORATION

TIGER BAY

ANOHR -49.416 * NOF + 12036.41

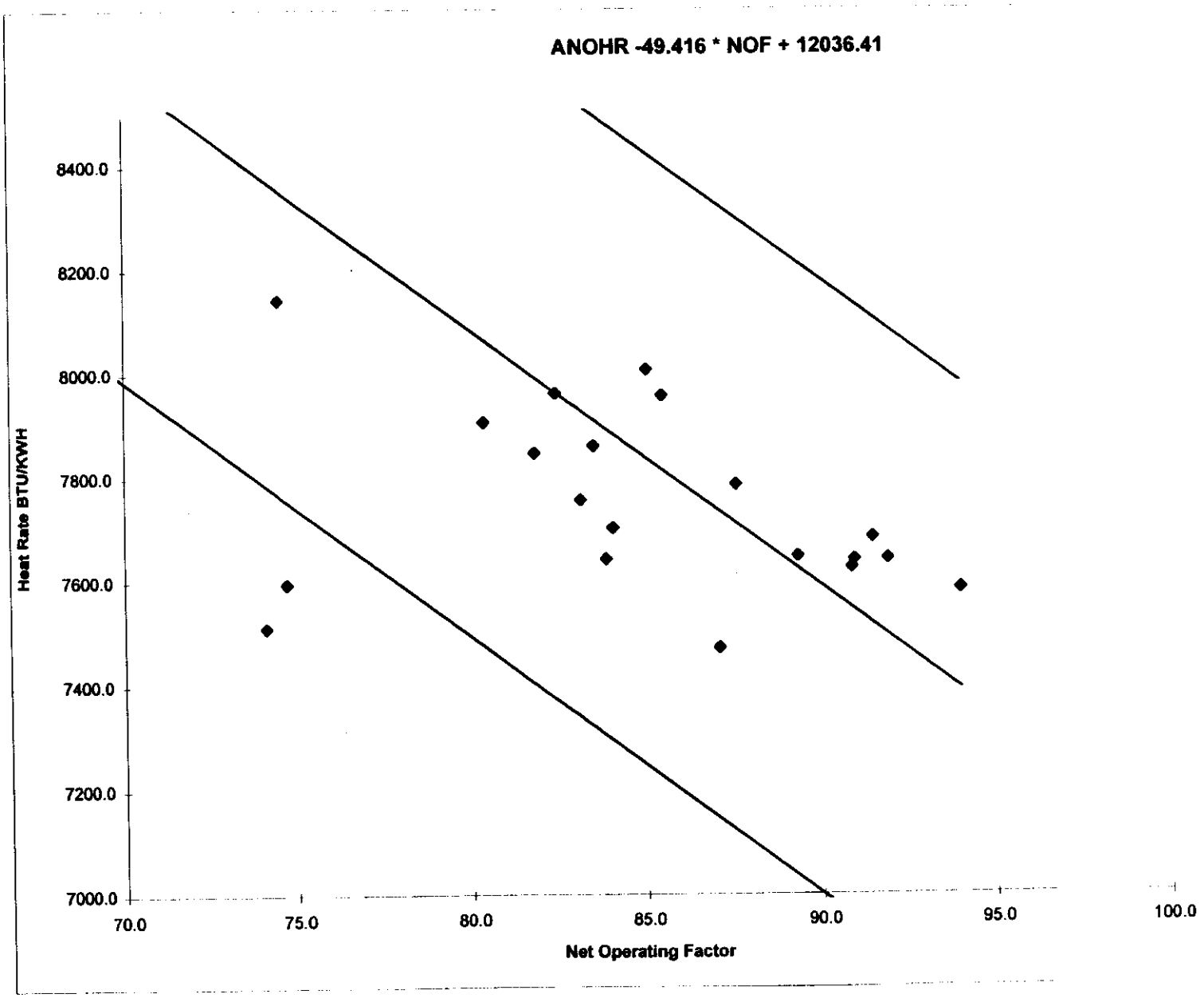
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-97	83.5	7861.0	7911.2	-50.2	590.3
Aug-97	90.9	7641.0	7545.0	96.0	590.3
Sep-97	94.0	7585.0	7393.3	191.7	590.3
Oct-97	90.8	7626.0	7548.5	77.5	590.3
Nov-97	87.5	7786.0	7711.1	74.9	590.3
Dec-97	85.0	8008.0	7835.6	172.4	590.3
Jan-98	91.9	7643.0	7496.6	146.4	590.3
Feb-98	84.0	7703.0	7884.0	-181.0	590.3
Mar-98	74.5	8144.0	8356.4	-212.4	590.3
Apr-98	83.8	7643.0	7893.9	-250.9	590.3
May-98	85.5	7958.0	7813.9	144.1	590.3
Jun-98	91.4	7684.0	7518.8	165.2	590.3
Jul-98	89.3	7648.0	7624.6	23.4	590.3
Aug-98	82.4	7963.0	7963.6	-0.6	590.3
Sep-98	80.3	7908.0	8066.4	-158.4	590.3
Oct-98	81.8	7848.0	7993.2	-145.2	590.3
Nov-98	74.1	7512.0	8376.2	-864.2	590.3
Dec-98	48.0	10053.0	9666.4	386.6	590.3
Jan-99	80.0	8962.0	8083.2	878.8	590.3
Feb-99	68.6	8847.0	8647.0	200.0	590.3
Mar-99	74.7	7596.0	8345.1	-749.1	590.3
Apr-99	76.7	8739.0	8248.7	490.3	590.3
May-99	87.1	7472.0	7734.8	-262.8	590.3
Jun-99	83.1	7757.0	7929.5	-172.5	590.3

Regression Output:

Constant	12036.41
Std Err of Y Est	366.5435361
R Squared	0.642343726
No. of Observations	24
Degrees of Freedom	23
X Coefficient	-49.4155283
Std Err of Coef.	7.861425131

Tiger Bay


ANOHR -49.416 * NOF + 12036.41
Heat Rate BTU/KWH
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8200.0
8000.0
7800.0
7600.0
7400.0
7200.0
7000.0
70.0
75.0
80.0
85.0
90.0
95.0
100.0
Net Operating Factor

UNPLANNED OUTAGE RATE

TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Company: Florida Power Corporation
Period of: January, 2000 - December, 2000

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Anclote 1	FOR	0.47	1.80	0.90
	MOR	0.97	3.71	1.86
	FOR&MOR	1.45	5.52	2.76
	EFOR	0.94	3.60	1.80
	EMOR	0.27	1.02	0.51
	EUOR	2.63	9.75	4.97
	EUOF	2.02	7.50	3.82
Anclote 2	FOR	0.22	0.86	0.43
	MOR	2.78	10.58	5.29
	FOR&MOR	3.00	11.44	5.72
	EFOR	1.50	5.71	2.86
	EMOR	0.37	1.40	0.70
	EUOR	4.80	17.58	9.03
	EUOF	3.46	12.66	6.50
Crystal River 1	FOR	0.59	2.24	1.12
	MOR	2.71	10.33	5.16
	FOR&MOR	3.30	12.57	6.28
	EFOR	1.77	6.73	3.37
	EMOR	0.36	1.36	0.68
	EUOR	5.32	19.24	9.97
	EUOF	5.19	18.76	9.72
Crystal River 2	FOR	2.97	11.31	5.65
	MOR	1.95	7.45	3.72
	FOR&MOR	4.92	18.76	9.38
	EFOR	1.71	6.51	3.25
	EMOR	0.20	0.77	0.39
	EUOR	6.63	23.24	12.29
	EUOF	5.39	18.90	9.99
Crystal River 3	FOR	2.20	8.38	4.19
	MOR	0.10	0.39	0.20
	FOR&MOR	2.30	8.77	4.38
	EFOR	0.80	3.04	1.52
	EMOR	0.41	1.56	0.78
	EUOR	3.48	12.91	6.57
	EUOF	3.48	12.91	6.57
Crystal River 4	FOR	2.22	8.46	4.23
	MOR	0.93	3.53	1.77
	FOR&MOR	3.15	12.00	6.00
	EFOR	0.93	3.54	1.77
	EMOR	0.62	2.37	1.18
	EUOR	4.61	16.67	8.63
	EUOF	3.81	13.78	7.14
Crystal River 5	FOR	0.77	2.95	1.48
	MOR	0.19	0.71	0.35
	FOR&MOR	0.96	3.66	1.83
	EFOR	0.77	2.92	1.46
	EMOR	0.48	1.83	0.92
	EUOR	2.19	8.20	4.15
	EUOF	2.14	7.99	4.05
Bartow 3	FOR	1.74	6.63	3.32
	MOR	0.44	1.66	0.83
	FOR&MOR	2.18	8.29	4.15
	EFOR	1.96	7.48	3.74
	EMOR	1.78	6.80	3.40
	EUOR	5.83	21.20	10.94
	EUOF	4.05	14.73	7.60
Tiger Bay	FOR	3.13	11.91	5.96
	MOR	0.81	3.08	1.54
	FOR&MOR	3.93	14.99	7.50
	EFOR	0.01	0.05	0.02
	EMOR	0.04	0.15	0.07
	EUOR	3.93	14.47	9.22
	EUOF	2.38	8.74	5.57

ANCLOTE
UNIT 1

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	665.6	725.8	722.1	720	655.6	190.9	335.9	319.4	278.7	403.6	569.2	744	632.4	723.1	710.4	720	566.6	61.1	444.1
RSH	0	0	0	0	89.4	351.5	404.7	407.2	386.4	327.2	0	1	2	3	4	5	135.2	83.2	278.8
UH	54.4	36.4	21.9	0	0	177.6	3.4	17.4	7	13.3	0	0	49.5	20.9	33.6	0	43.2	575.7	21.1
POH	0	18.2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	575.7	11.9
FOH	54.4	7.9	3.4	0	0	0	3.4	0	0	0	0	0	34.8	20.9	33.6	0	2.2	0	0
MOH	0	10.3	18.5	0	0	177.6	0	17.4	7	13.3	0	0	14.7	0	0	0	0	0	9.2
PFOH	65.4	75.3	118.2	61.4	145.5	85.9	0	6.4	4.2	31.4	62.4	33.4	45	34.8	52.9	48.7	161.9	0	8.1
LRPF	169.7	177.3	148.2	23.5	176.4	159.9	0	169.8	325.6	183.9	169.7	174.7	130.4	169.7	169.7	169.7	69.5	0	169.7
EFOH	21.7	26.1	34.3	2.8	50.2	26.9	0	2.1	2.7	11.3	20.7	11.4	11.5	11.6	17.6	16.2	22	0	2.7
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	7.56	1.08	0.47	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	5.22	2.81	4.52	0.00	0.39	0.00	0.00
MOR	0.00	1.40	2.50	0.00	0.00	48.20	0.00	5.17	2.45	3.19	0.00	0.00	2.27	0.00	0.00	0.00	0.00	0.00	2.03
PFOR	3.26	3.60	4.75	0.39	7.66	14.09	0.00	0.66	0.97	2.80	3.64	1.53	1.82	1.60	2.48	2.25	3.88	0.00	0.61
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	10.57	5.95	7.55	0.39	7.66	55.50	1.00	5.79	3.40	5.90	3.64	1.53	8.95	4.37	6.88	2.25	4.25	0.00	2.63
EUOF	10.57	5.95	7.55	0.39	6.74	28.40	0.46	2.62	1.44	3.31	2.88	1.53	8.47	4.37	6.88	2.25	3.25	0.00	1.60
POF	0.00	2.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.50	79.96	1.60
EAF	89.43	91.60	92.45	99.61	93.26	71.60	99.54	97.38	98.56	96.69	97.12	98.47	91.53	95.63	93.12	97.75	91.25	20.04	96.80

12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	1.14	1.26	1.32	1.32	1.26	1.31	1.38	1.41	1.40	1.09	1.08	1.08	0.78	0.98	1.45	1.45	1.51	1.54	1.46
MOR	1.31	1.47	1.77	1.76	1.68	3.26	3.30	3.65	3.74	3.85	3.71	3.71	3.95	3.80	3.53	3.53	3.58	0.86	0.99
PFOR	2.43	2.46	2.47	2.16	2.82	3.34	3.33	3.38	3.40	3.49	3.59	3.32	3.18	2.95	2.69	2.90	2.49	2.10	2.10
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	4.79	5.09	5.43	5.13	5.63	7.68	7.76	8.17	8.27	8.18	8.14	7.88	7.69	7.52	7.44	7.64	7.35	4.42	4.47
EUOF	3.51	3.73	3.98	3.77	4.34	5.76	5.76	5.93	6.06	6.13	6.17	5.97	5.80	5.67	5.61	5.76	5.47	3.13	3.23
POF	11.96	12.17	12.17	11.89	8.07	8.07	8.07	8.07	5.22	0.21	0.21	0.21	0.21	0.00	0.00	0.00	0.47	7.04	7.18
EAF	84.53	84.10	83.85	84.34	87.59	86.17	86.17	86.00	88.72	93.66	93.62	93.82	93.99	94.33	94.39	94.24	94.07	89.83	89.59

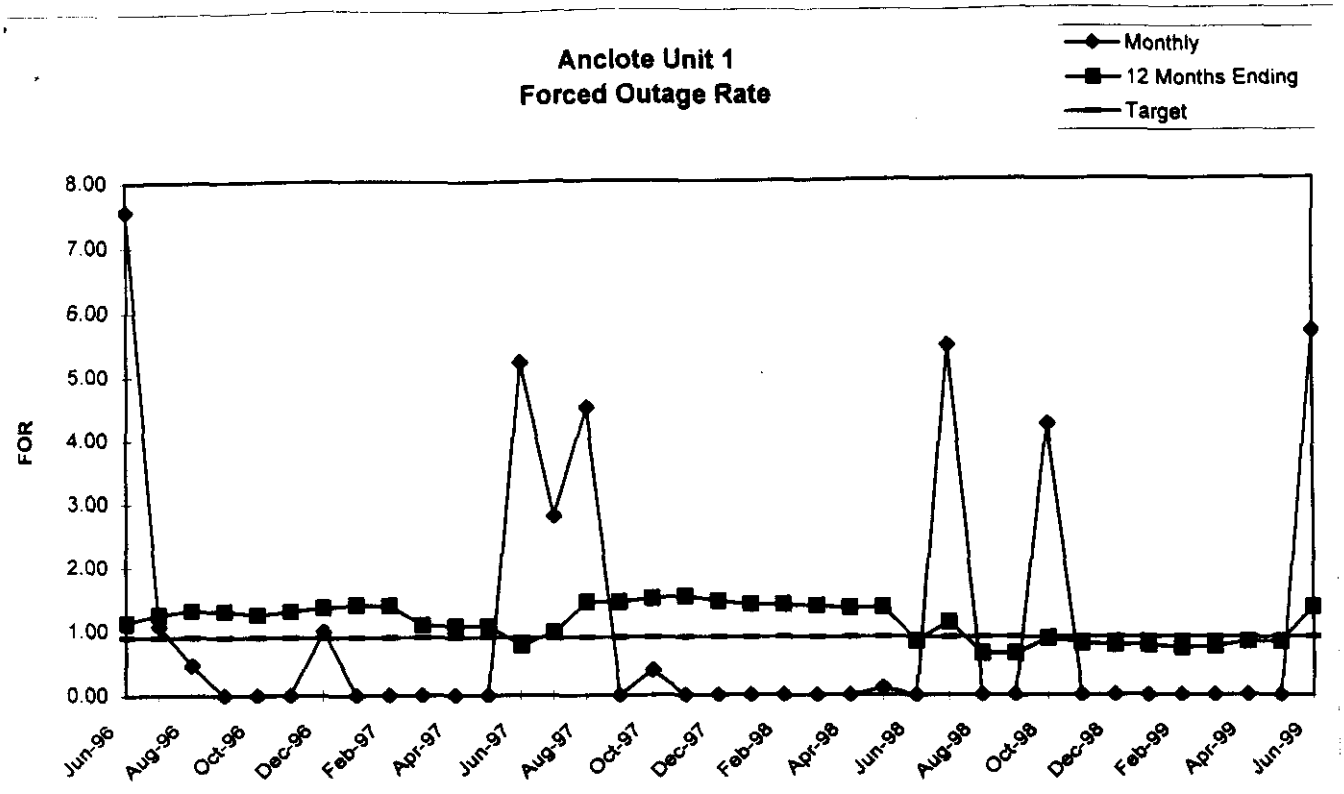
ANCLOTE
UNIT 1

	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	548.1	286.4	505.1	719	743.2	720	703.3	744	720	385.5	720.0	744.0	583.98	672.00	292.20	0.00	652.97	615.83
RSH	195.9	385.6	24	0	0	0	0	0	0	0.0	0.0	0.0	160.02	0.00	0.00	0.00	0.00	0.00
UH	0	0	214.9	0	0.8	0	40.7	0	0	359.5	0.0	0.0	0.00	0.00	451.80	719.00	91.03	104.17
POH	0	0	214.9	0	0	0	0	0	0	342.5	0.0	0.0	0.00	0.00	451.80	719.00	91.03	0.00
FOH	0	0	0	0	0.8	0	40.7	0	0	17.1	0.0	0.0	0.00	0.00	0.00	0.00	0.00	37.03
MOH	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	67.13
PFOH	0	0	0	9.4	9.1	20	187.1	3.3	0	146.8	24.7	14.0	3.00	0.00	0.00	0.00	32.67	9.85
LRPF	0	0	0	227.8	66.4	249.8	18	156.9	0	14.6	165.8	319.1	257.30	0.00	0.00	0.00	109.40	197.71
EFOH	0	0	0	4.19	1.18	9.78	6.59	1.01	0.00	4.20	8.00	8.73	1.51	0.00	0.00	0.00	6.99	3.81
PMOH	0	4	3.5	48.3	53.0	40.7	96.9	76.6	48.5	10.2	24.1	0.0	0.00	23.00	0.00	0.00	22.65	55.58
LRPM	0	169.9	267.2	169.7	169.7	164.2	95.8	149.3	165.5	155.0	163.4	0.0	0.00	169.65	0.00	0.00	173.54	132.80
EMOH	0	1.32994	1.83014	16.0392	17.5999	13.09	18.17	22.38	15.71	3.09	7.71	0.00	0.00	7.64	0.00	0.00	7.69	14.44
NPC	511	511	511	511	511	511	511	511	511	511	511	511	511.00	511.00	511.00	511.00	511.00	511.00

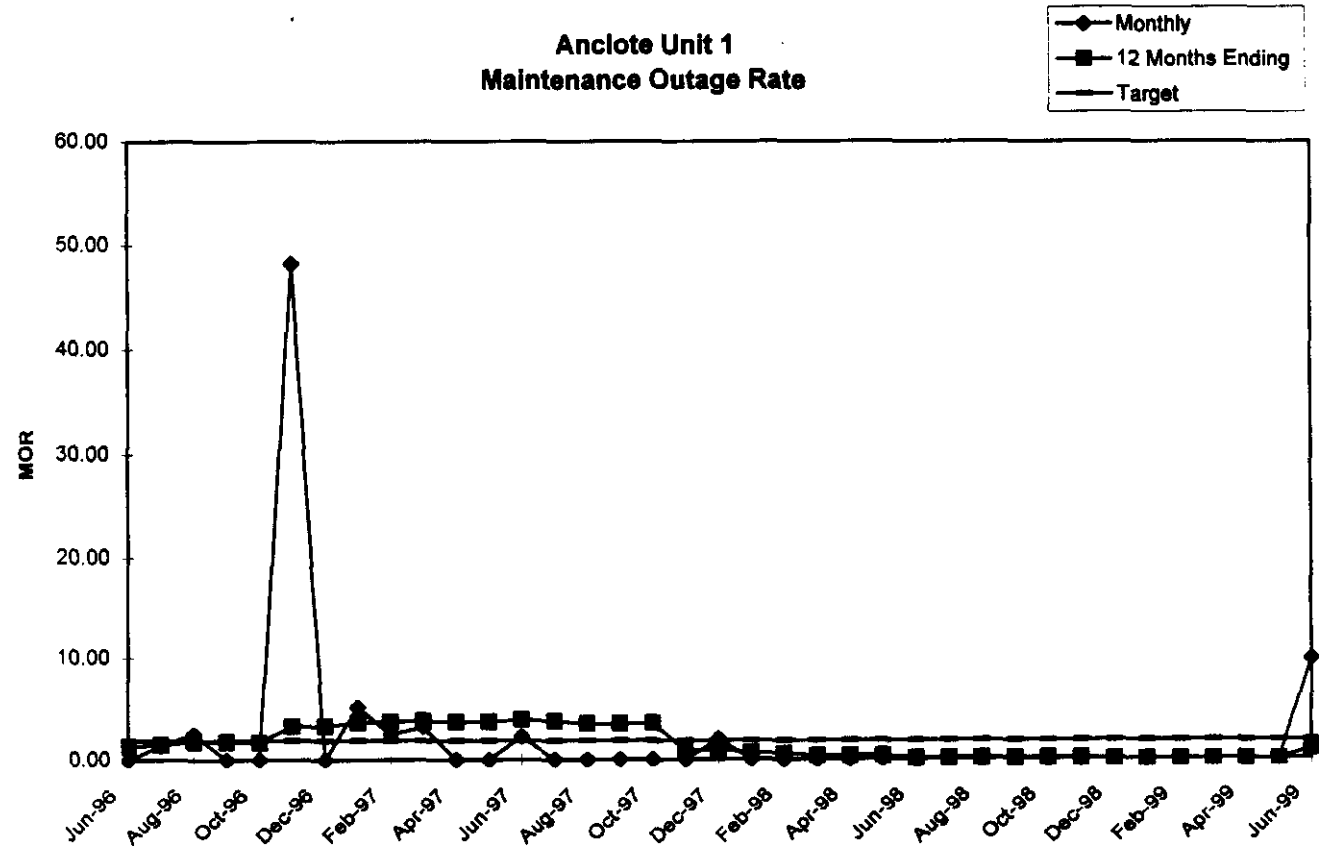
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.00	0.00	0.00	0.00	0.11	0.00	5.47	0.00	0.00	4.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.67
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.83
PFOR	0.00	0.00	0.00	0.58	0.16	1.36	0.94	0.14	0.00	1.09	1.11	1.17	0.26	0.00	0.00	0.00	1.07	0.62
PMOR	0.00	0.46	0.36	2.23	2.37	1.82	2.58	3.01	2.18	0.80	1.07	0.00	0.00	1.14	0.00	0.00	1.18	2.35
EUOR	0.00	0.46	0.36	2.81	2.63	3.18	8.80	3.14	2.18	6.05	2.18	1.17	0.26	1.14	0.00	0.00	2.25	17.00
EUOF	0.00	0.20	0.25	2.81	2.63	3.18	8.80	3.14	2.18	3.27	2.18	1.17	0.20	1.14	0.00	0.00	1.97	17.00
POF	0.00	0.00	28.88	0.00	0.00	0.00	0.00	0.00	0.00	45.97	0.00	0.00	0.00	0.00	60.73	100.00	12.24	0.00
EAF	100.00	99.80	70.87	97.19	97.37	96.82	91.20	96.86	97.82	50.76	97.82	98.83	99.80	98.86	39.27	0.00	85.79	83.00

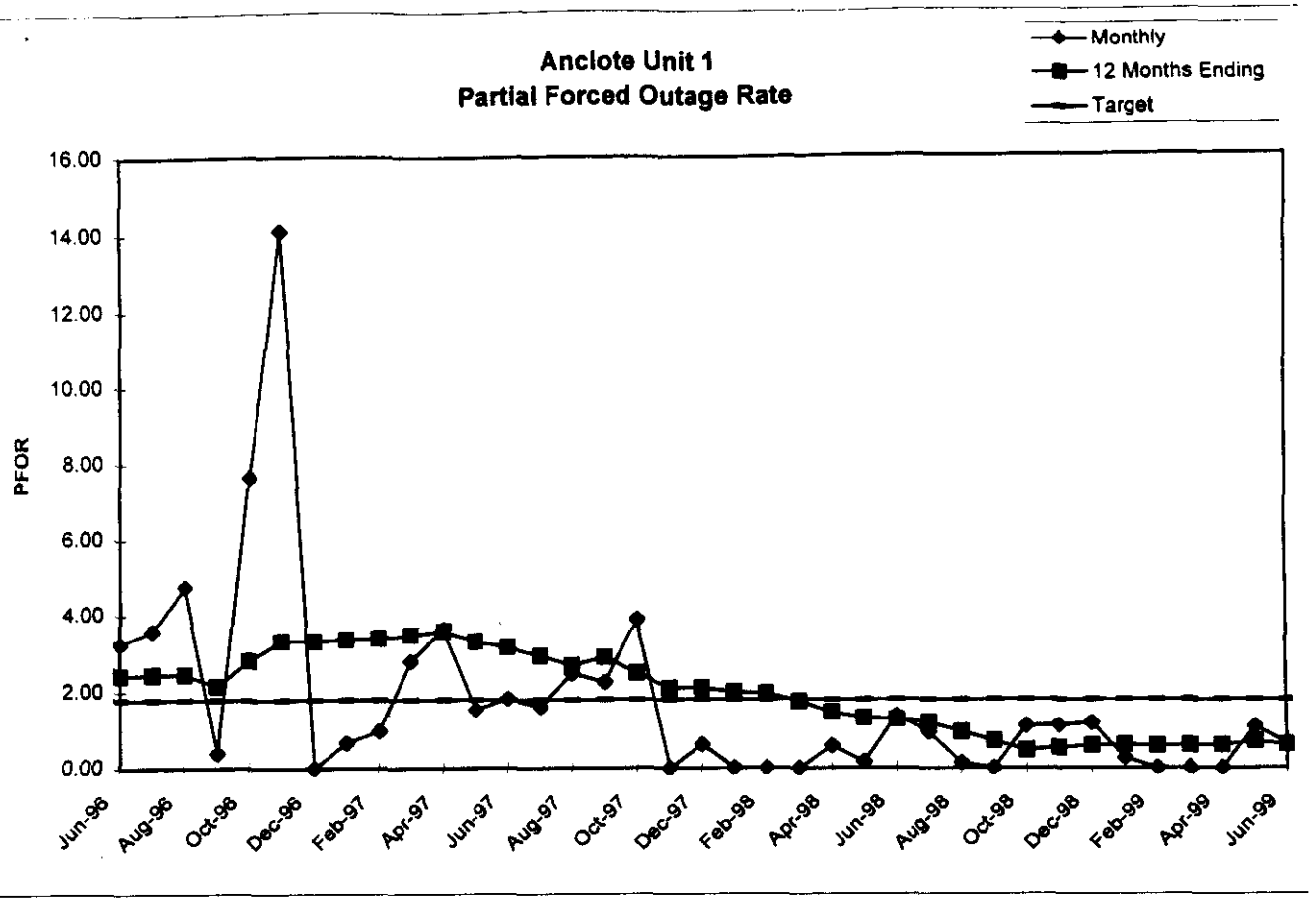
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	1.41	1.41	1.39	1.36	1.37	0.85	1.14	0.64	0.64	0.88	0.80	0.77	0.77	0.73	0.75	0.83	0.83	1.37
MOR	0.69	0.58	0.37	0.36	0.36	0.14	0.14	0.14	0.14	0.14	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.97
PFOR	1.99	1.95	1.75	1.46	1.31	1.26	1.19	0.94	0.70	0.45	0.52	0.58	0.60	0.57	0.58	0.58	0.67	0.60
PMOR	0.00	0.02	0.05	0.29	0.55	0.74	1.01	1.34	1.57	1.66	1.62	1.55	1.54	1.55	1.57	1.50	1.38	1.42
EUOR	4.03	3.90	3.51	3.42	3.54	2.96	3.45	3.04	3.03	3.11	3.04	2.89	2.89	2.83	2.88	2.89	2.86	4.28
EUOF	3.01	2.91	2.65	2.65	2.74	2.30	2.68	2.36	2.36	2.36	2.54	2.50	2.52	2.59	2.57	2.34	2.28	3.42
POF	7.18	7.18	9.63	9.63	9.63	9.63	9.63	9.63	9.63	13.07	6.50	6.36	6.36	6.36	9.07	17.27	18.31	18.31
EAF	89.82	89.91	87.72	87.73	87.63	88.07	87.69	88.01	88.01	84.57	90.96	91.14	91.12	91.05	88.36	80.39	79.40	78.27

Anclote Unit 1
Forced Outage Rate



Anclote Unit 1
Maintenance Outage Rate




Anclote Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
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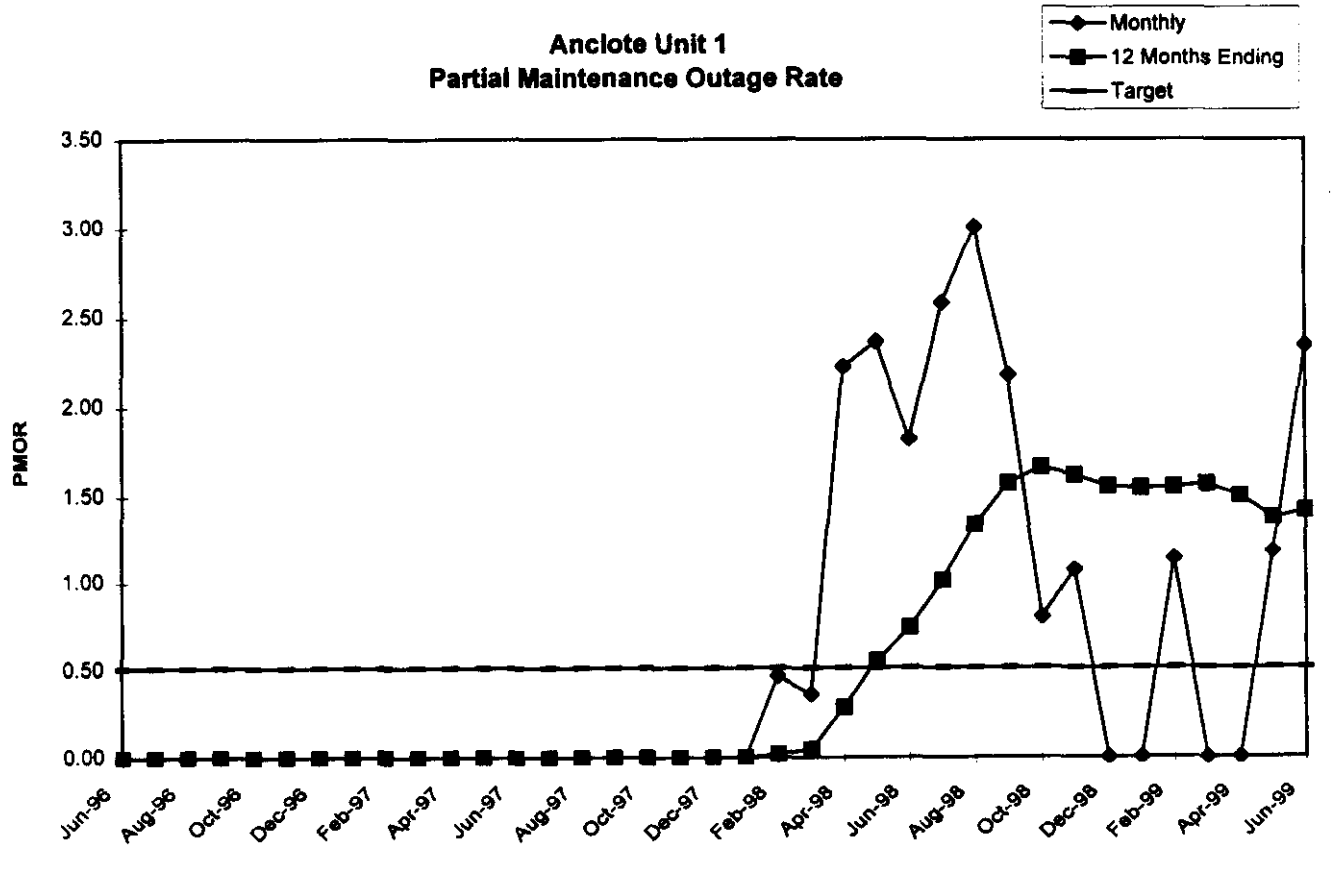
Apr-99
Jun-99


Anclote Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
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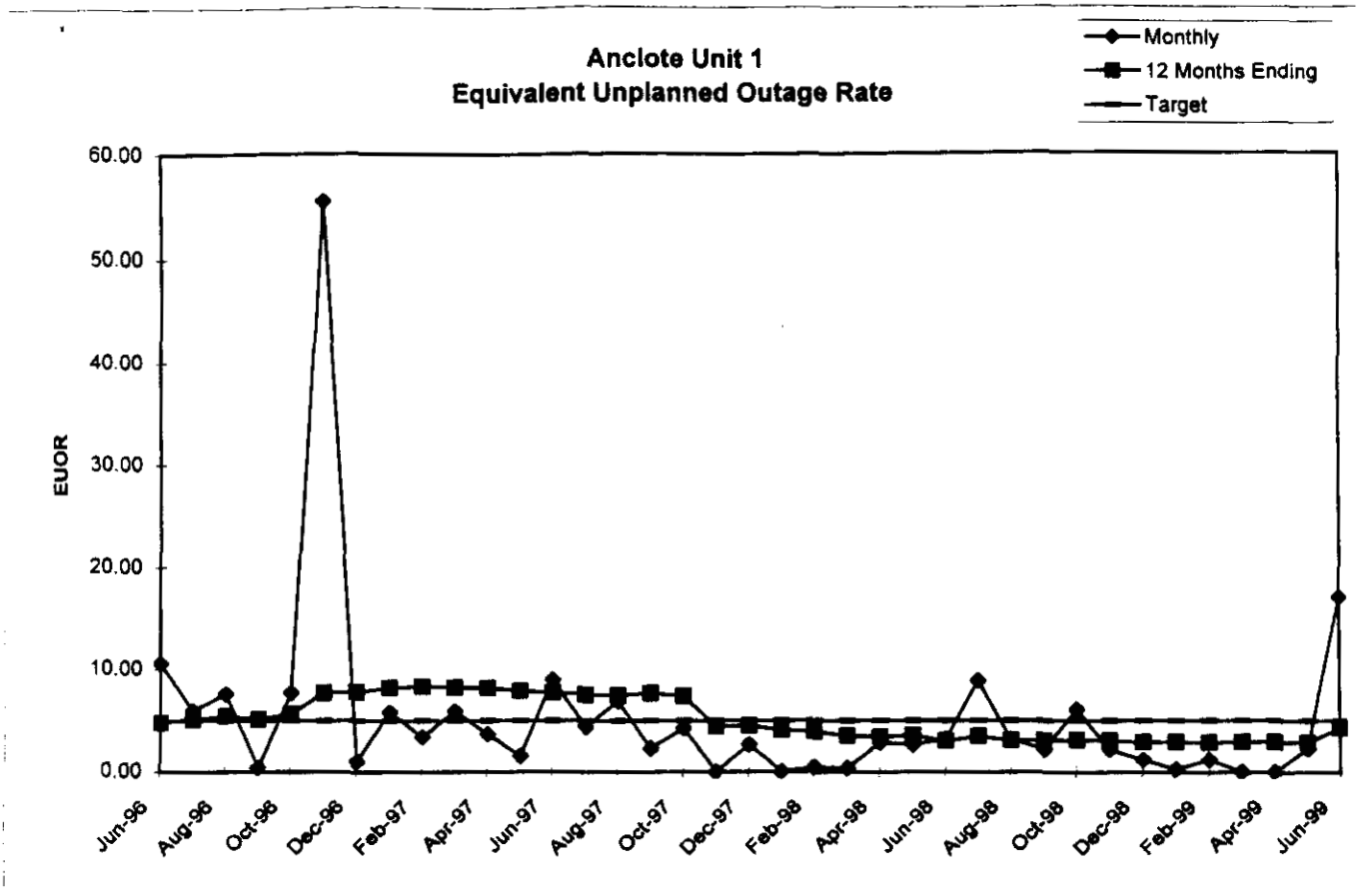
Feb-99
Apr-99
Jun-99


Anclote Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
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Dec-97
Feb-98
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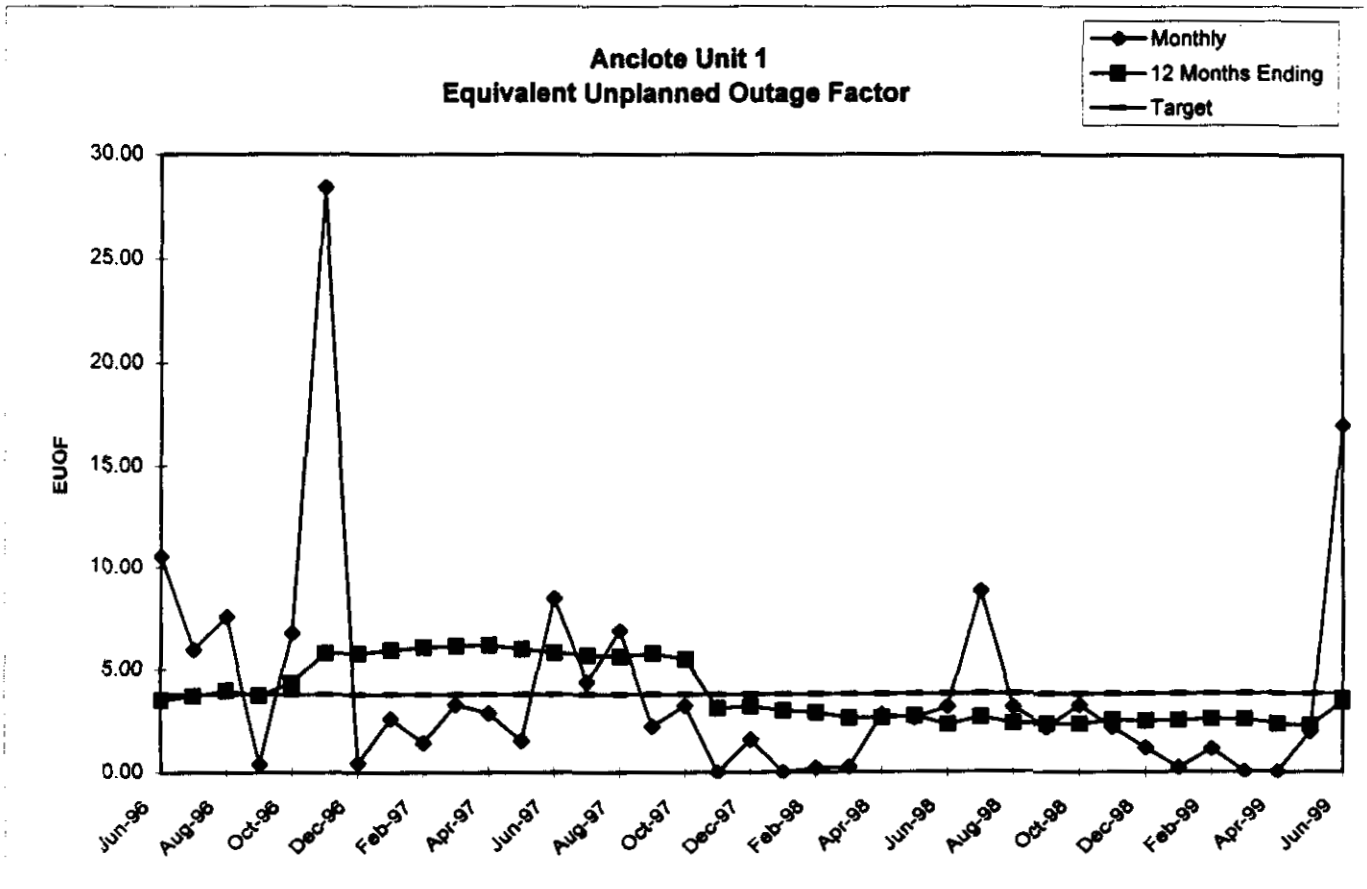
Apr-99
Jun-99


Anclote Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

ANCLOTE
UNIT 2

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	692.4	744	744	677.6	191.1	0	42.1	324.1	605.7	744	448.8	692.2	679	714.3	720	718.2	666.4	590	431.1
RSH	0	0	0	0	39.9	0	205.5	414	66.3	0	40.2	0	0	0	0	0	78.6	89	0
UH	27.6	0	0	42.4	514	720	496.4	5.9	0	0	0	51.8	41	29.7	24	1.8	0	41	312.9
POH	0	0	0	0	514	720	496.4	0	0	0	0	0	0	0	0	0	0	41	311.5
FOH	0	0	0	0	0	0	0	5.9	0	0	0	0	7.4	0	24	1.4	0	0	1.4
MOH	27.6	0	0	42.4	0	0	0	0	0	0	0	51.8	33.6	29.7	0	0.3	0	0	0
PFOH	89.9	169	227.4	133.5	24.6	0	0	7.1	61.4	59.4	117.2	397.4	223.8	790.4	770.2	761.4	762.8	1034.7	0
LRPF	184.5	105.6	74	68.1	15.6	0	0	170.3	22.2	176.2	48.4	31.1	48.1	24.5	19.8	23.4	19.4	25.6	0
EFOH	32.5	34.9	32.9	17.8	0.8	0	0	2.4	2.7	20.5	11.1	24.2	21.1	37.9	29.8	34.9	29	51.6	0
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511	511

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.79	0.00	0.00	0.00	0.00	1.08	0.00	3.23	0.19	0.00	0.00	0.32
MOR	3.83	0.00	0.00	5.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.96	4.72	3.99	0.00	0.04	0.00	0.00	0.00
PFOR	4.69	4.69	4.42	2.63	0.42	0.00	0.00	0.74	0.45	2.76	2.47	3.50	3.11	5.31	4.14	4.86	4.35	8.78	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	8.35	4.69	4.42	8.36	0.42	0.00	0.00	2.52	0.45	2.76	2.47	10.22	8.63	9.09	7.23	5.08	4.35	8.78	0.32
EUOF	8.35	4.69	4.42	8.36	0.11	0.00	0.00	1.12	0.40	2.76	1.54	10.22	8.63	9.09	7.23	5.08	3.89	7.19	0.19
POF	0.00	0.00	0.00	0.00	68.99	100.00	66.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.69	41.87
EAF	91.65	95.31	95.58	91.64	30.90	0.00	33.28	98.88	99.60	97.24	98.46	89.78	91.38	90.91	92.77	94.92	96.11	87.11	57.94

12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	0.34	0.33	0.33	0.33	0.34	0.34	0.36	0.47	0.40	0.09	0.10	0.10	0.23	0.23	0.63	0.65	0.61	0.55	0.54
MOR	0.94	0.94	0.94	1.58	1.62	1.28	1.34	1.39	1.37	1.11	1.16	2.02	2.12	2.62	2.63	1.92	1.78	1.63	1.55
PFOR	6.62	6.11	5.11	4.95	4.98	2.89	3.03	2.94	2.76	2.91	3.04	3.04	2.86	2.92	2.88	3.15	3.36	3.82	3.62
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	7.81	7.30	6.31	6.76	6.83	4.46	4.67	4.73	4.47	4.08	4.26	5.10	5.13	5.67	6.02	5.63	5.65	5.91	5.62
EUOF	5.90	5.51	4.76	5.10	5.05	3.24	3.24	3.17	3.05	2.94	2.93	3.51	3.53	3.91	4.14	3.88	4.20	4.79	4.80
POF	10.10	10.10	10.10	10.10	11.34	18.00	23.65	23.65	23.71	19.75	19.75	19.75	19.75	19.75	19.75	19.75	13.89	6.13	4.02
EAF	83.99	84.38	85.13	84.79	83.61	78.76	73.11	73.18	73.24	77.31	77.32	76.74	76.71	76.34	76.10	76.37	81.92	89.08	91.17

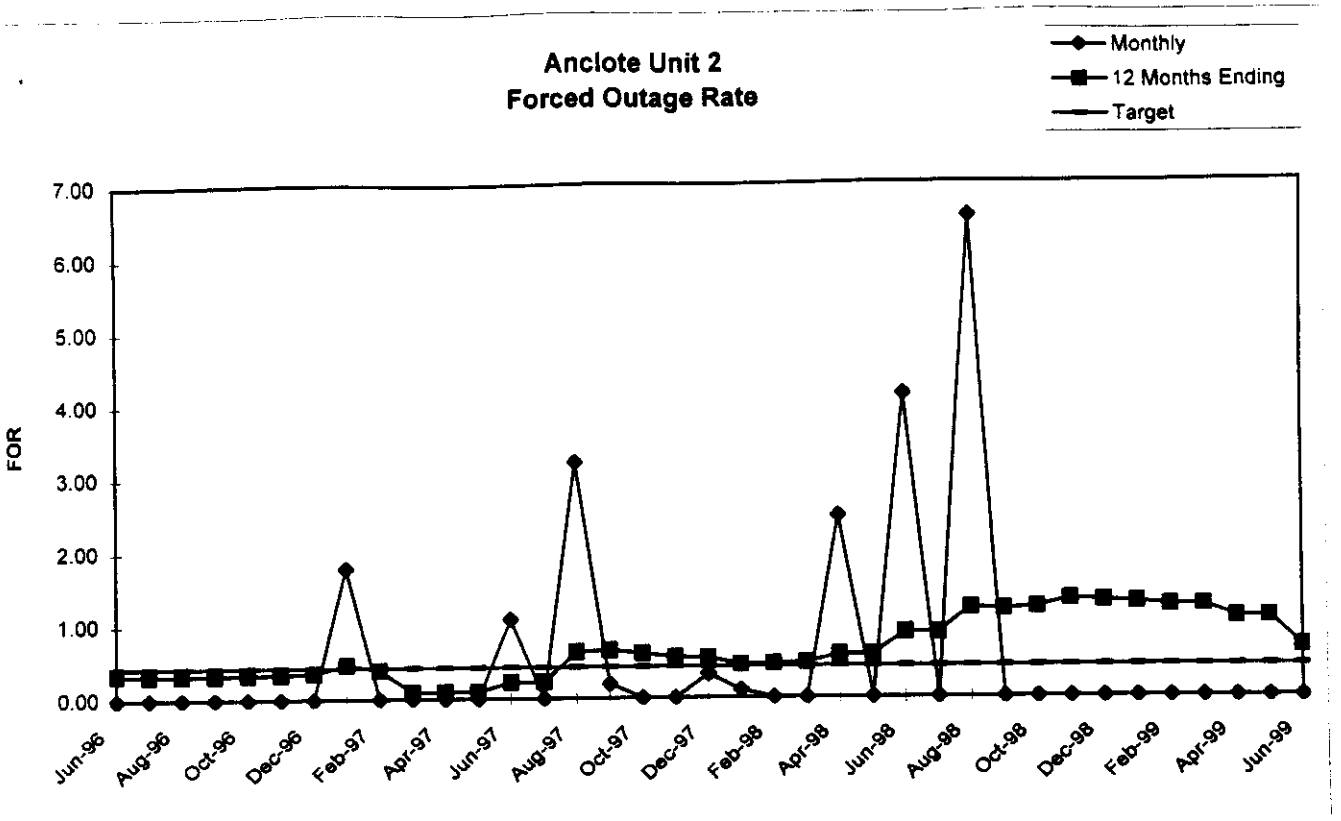
ANCLOTE
UNIT 2

	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744.0	672.0	744.0	719.0	744.0	720.0
SER HOURS	685.8	407.5	568.1	265.5	744.0	690.2	744	689.3	720	528.6	0.0	458.8	744.0	624.3	550.6	719.0	690.2	612.9
RSH	57.4	264.5	6.9	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
UH	0.7	0	169.1	453.6	0.0	29.8	0	54.7	0	216.5	720.0	285.2	0.0	0.0	193.4	0.0	53.9	107.1
POH	0	0	169.1	0	0	0	0	0	0	216.5	720.0	285.2	0.0	0.0	0.0	0.0	0.0	0.0
FOH	0.7	0	0	6.7	0.0	29.8	0	48.3	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MOH	0	0	0	446.8	0.0	0.0	0	6.5	0	0.0	0.0	0.0	0.0	47.7	193.4	0.0	53.9	107.1
PFOH	0	0	217.5	102.3	25.2	199.9	24.1	24.4	0	0.0	0.0	2.4	13.8	279.3	9.5	36.5	3.0	9.8
LRPF	0	0	102.7	96.1	21.3	82.3	51.1	44.6	0	0.0	0.0	427.7	167.6	73.0	434.4	116.7	28.6	199.9
EFOH	0	0	43.7	19.22	1.05	32.19	2.41	2.13	0.00	0.00	0.00	1.97	4.51	39.90	8.05	8.34	0.17	3.84
PMOH	0	4.1	9.7	26.3	61.7	51.2	70.3	80.1	43	44.8	0.0	0.0	25.2	34.9	0.0	21.4	48.1	43.0
LRPM	0	170.2	68.1	130.3	196.7	165.4	164.9	164.8	165.8	170.4	0.0	0.0	163.9	222.2	0.0	190.0	165.8	176.7
EMOH	0	1.4	1.3	6.71	23.77	16.58	22.69	25.83	13.95	14.95	0.00	0.00	8.07	15.17	0.00	7.96	15.59	14.86
NPC	511	511	511	511	511	511	511	511	511	511	511	511	511.0	511.0	511.0	511.0	511.0	511.0

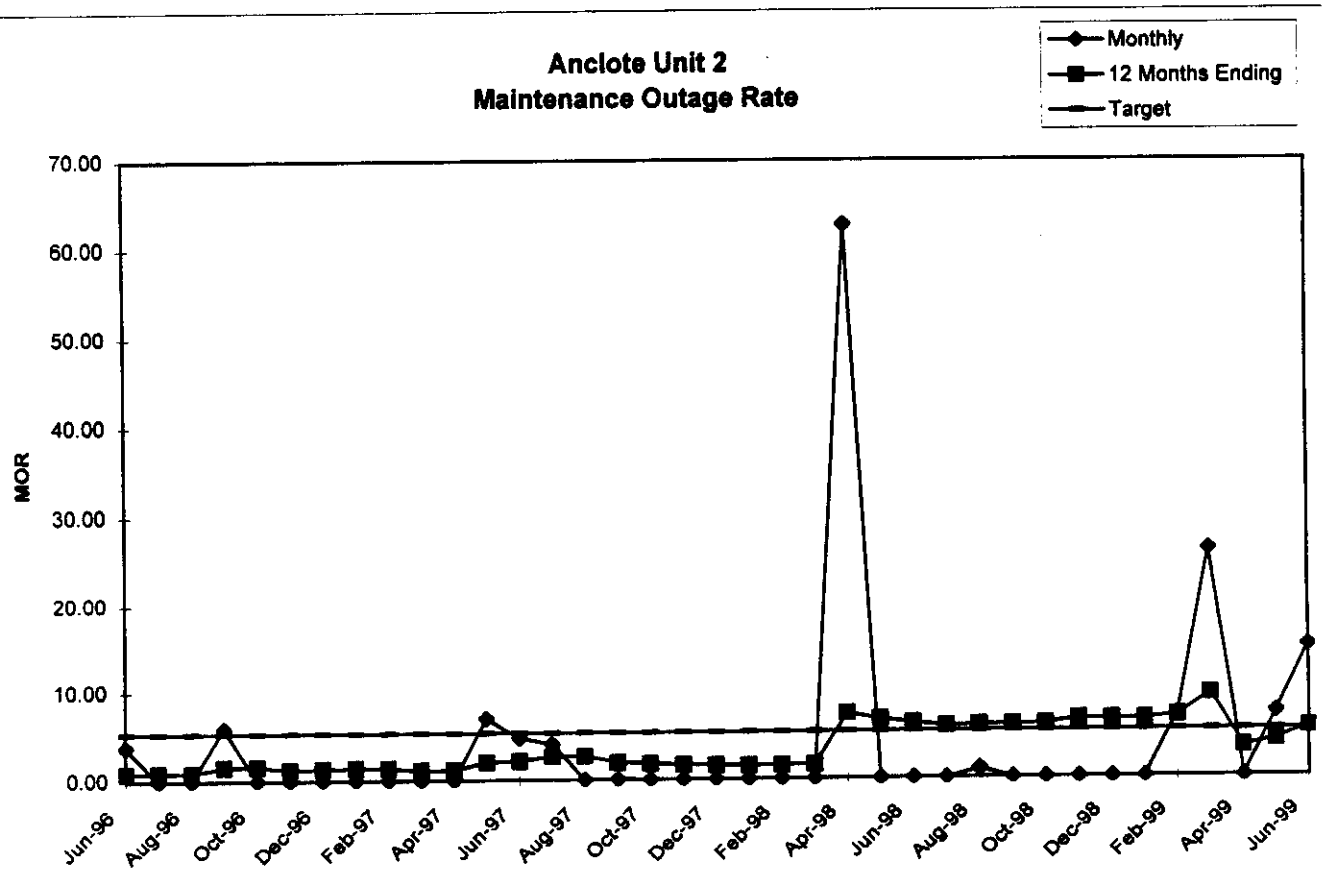
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.10	0.00	0.00	2.47	0.00	4.14	0.00	6.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	62.73	0.00	0.00	0.00	0.93	0.00	0.00	0.00	0.00	0.00	7.10	25.99	0.00	7.24	14.87
PFOR	0.00	0.00	7.69	7.24	0.14	4.66	0.32	0.31	0.00	0.00	0.00	0.43	0.61	6.39	1.46	1.16	0.02	0.63
PMOR	0.00	0.34	0.23	2.53	3.19	2.40	3.05	3.75	1.94	2.83	0.00	0.00	1.08	2.43	0.00	1.11	2.26	2.42
EUOR	0.10	0.34	7.92	66.69	3.34	10.92	3.37	11.12	1.94	2.83	0.00	0.43	1.69	15.29	27.08	2.27	9.36	17.47
EUOF	0.09	0.21	6.05	66.69	3.34	10.92	3.37	11.12	1.94	2.01	0.00	0.26	1.69	15.29	27.08	2.27	9.36	17.47
POF	0.00	0.00	22.73	0.00	0.00	0.00	0.00	0.00	0.00	29.05	100.00	38.33	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.91	99.79	71.22	33.31	96.66	89.08	96.63	88.88	98.06	68.94	0.00	61.40	98.31	84.71	72.92	97.73	90.64	82.53

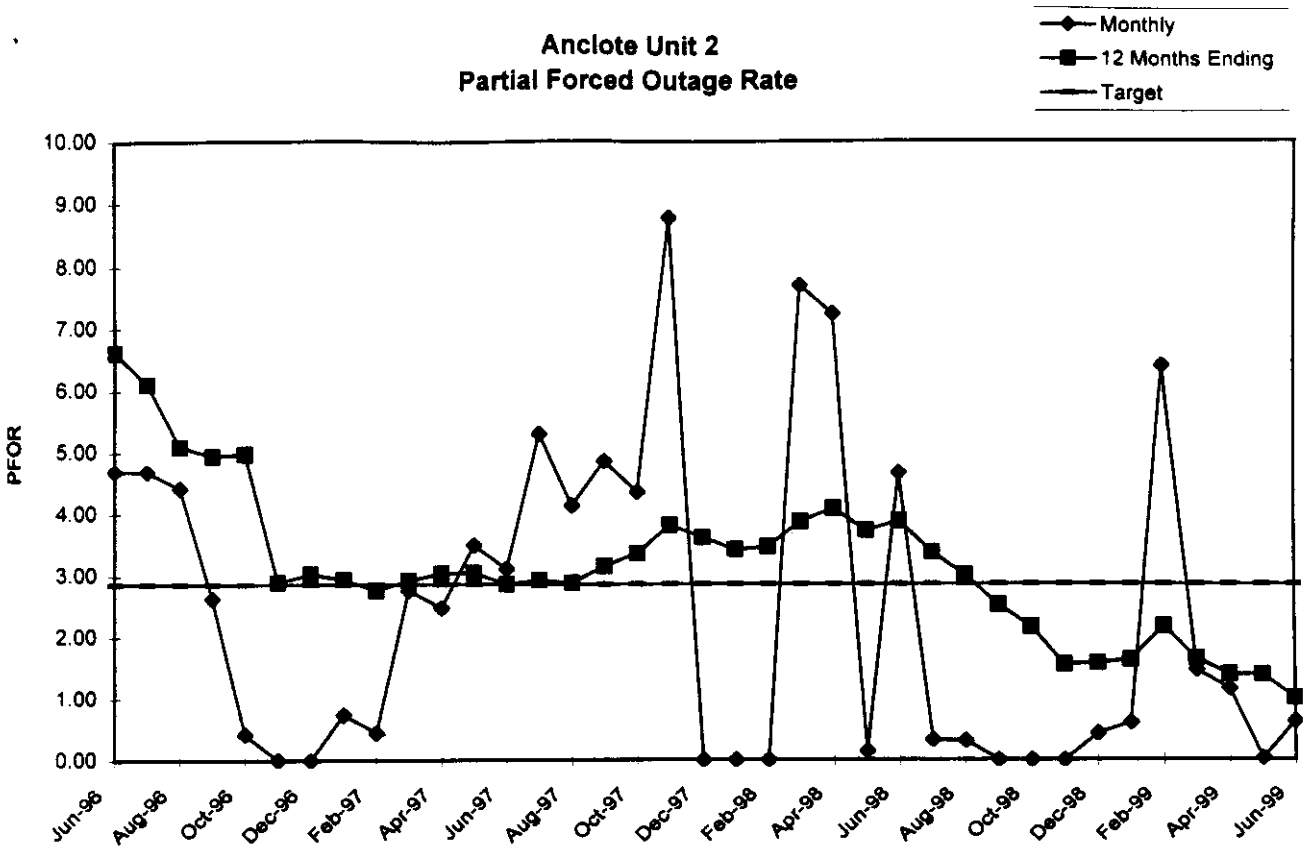
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.45	0.46	0.47	0.58	0.58	0.88	0.88	1.21	1.19	1.22	1.33	1.30	1.28	1.24	1.24	1.07	1.08	0.68
MOR	1.48	1.52	1.55	7.30	6.63	6.21	5.82	5.93	5.92	6.03	6.54	6.52	6.46	6.88	9.32	3.32	4.04	5.45
PFOR	3.42	3.47	3.87	4.09	3.73	3.88	3.38	3.01	2.52	2.16	1.56	1.58	1.63	2.17	1.65	1.39	1.39	1.01
PMOR	0.00	0.02	0.04	0.13	0.46	0.69	1.00	1.36	1.56	1.80	1.96	1.96	2.06	2.20	2.19	2.07	1.97	1.96
EUOR	5.27	5.39	5.84	11.69	11.03	11.24	10.69	11.06	10.77	10.78	10.95	10.92	11.00	11.98	13.77	7.63	8.22	8.85
EUOF	4.72	4.70	4.98	10.33	9.75	9.93	9.45	9.78	9.52	9.36	8.77	8.78	8.91	10.07	11.85	6.57	7.08	7.62
POF	4.02	4.02	5.95	5.95	5.95	5.95	5.95	5.95	5.95	8.43	16.18	15.88	15.88	15.88	13.95	13.95	13.95	13.95
EAF	91.26	91.27	89.06	83.72	84.30	84.11	84.60	84.27	84.53	82.21	75.05	75.35	75.21	74.06	74.20	79.49	78.98	78.44

Anclote Unit 2
Forced Outage Rate



Anclote Unit 2
Maintenance Outage Rate




Anclote Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
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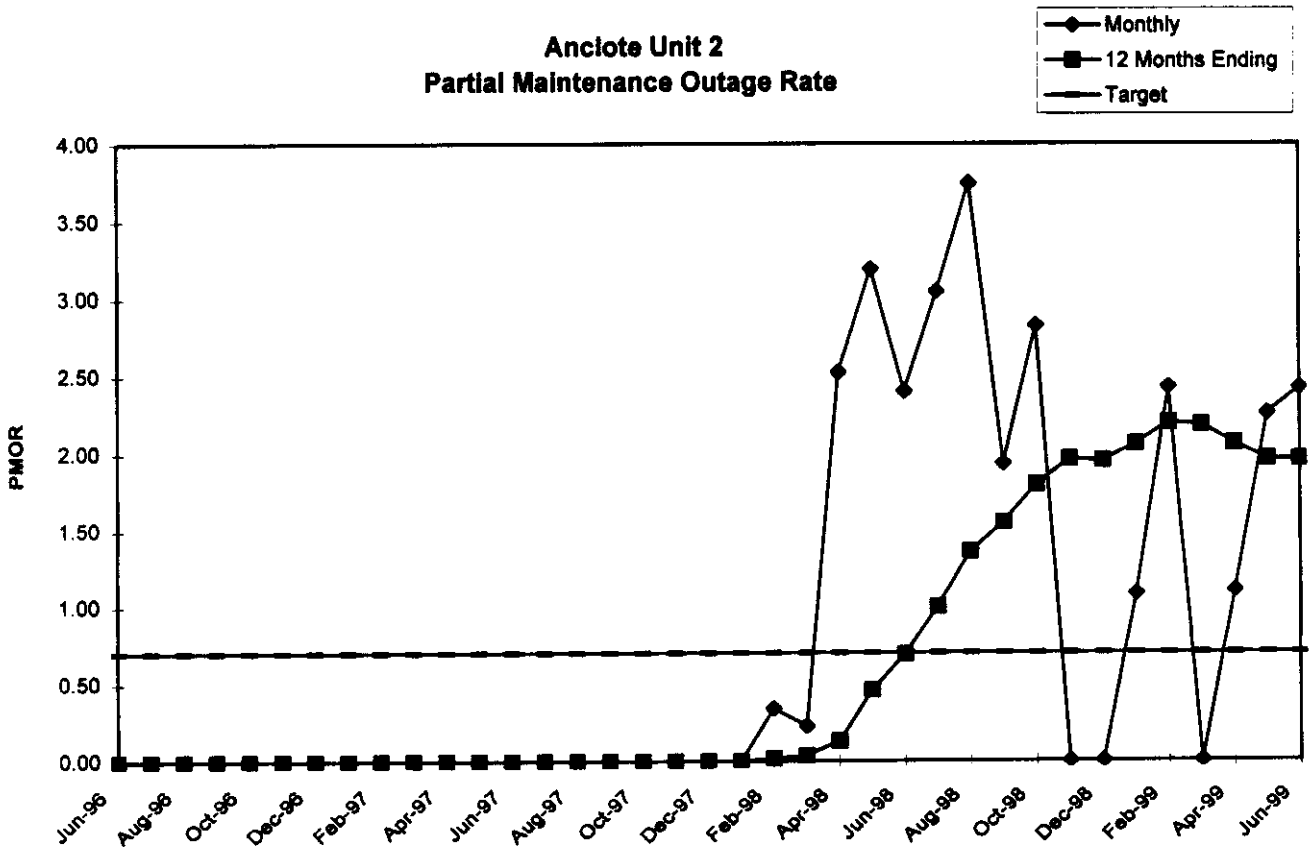
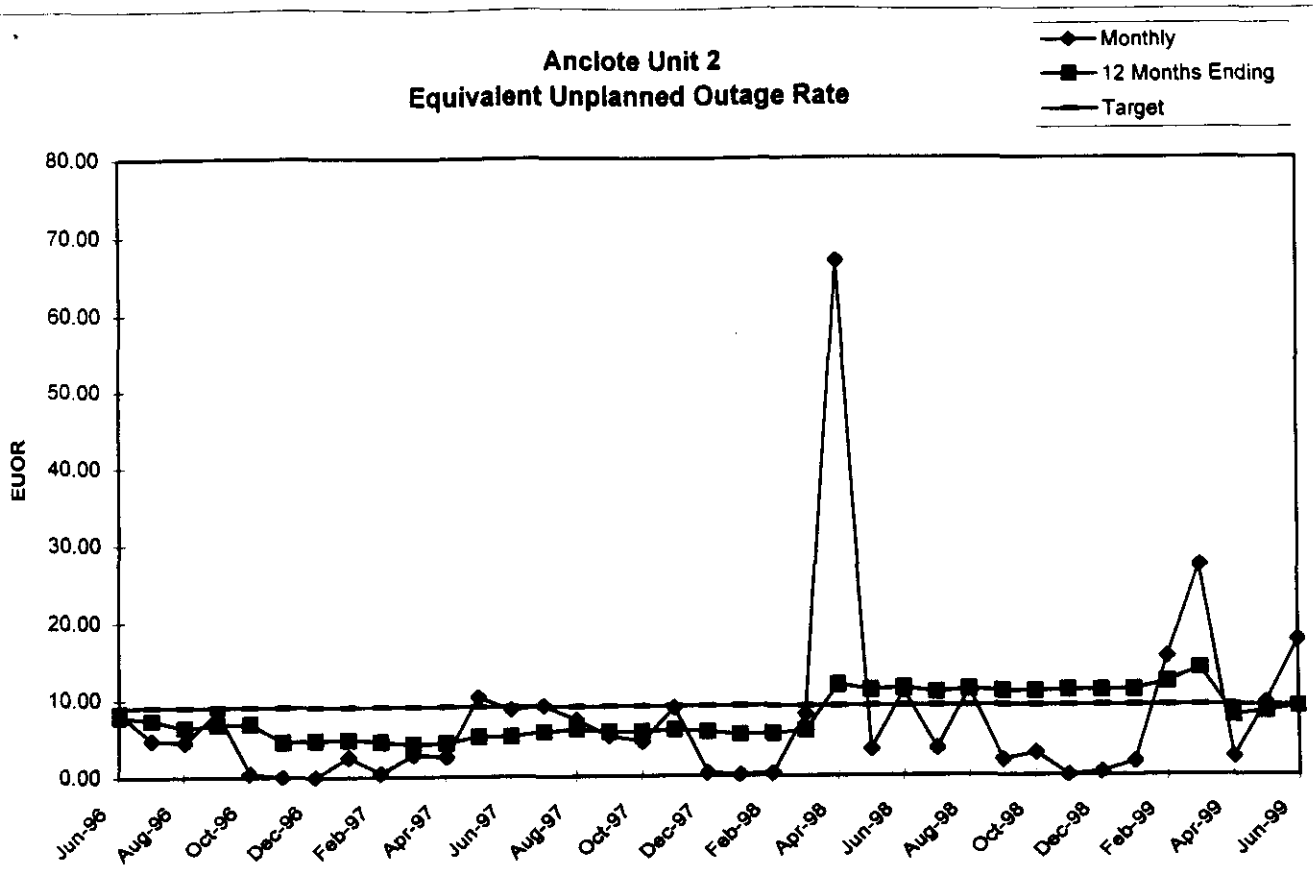
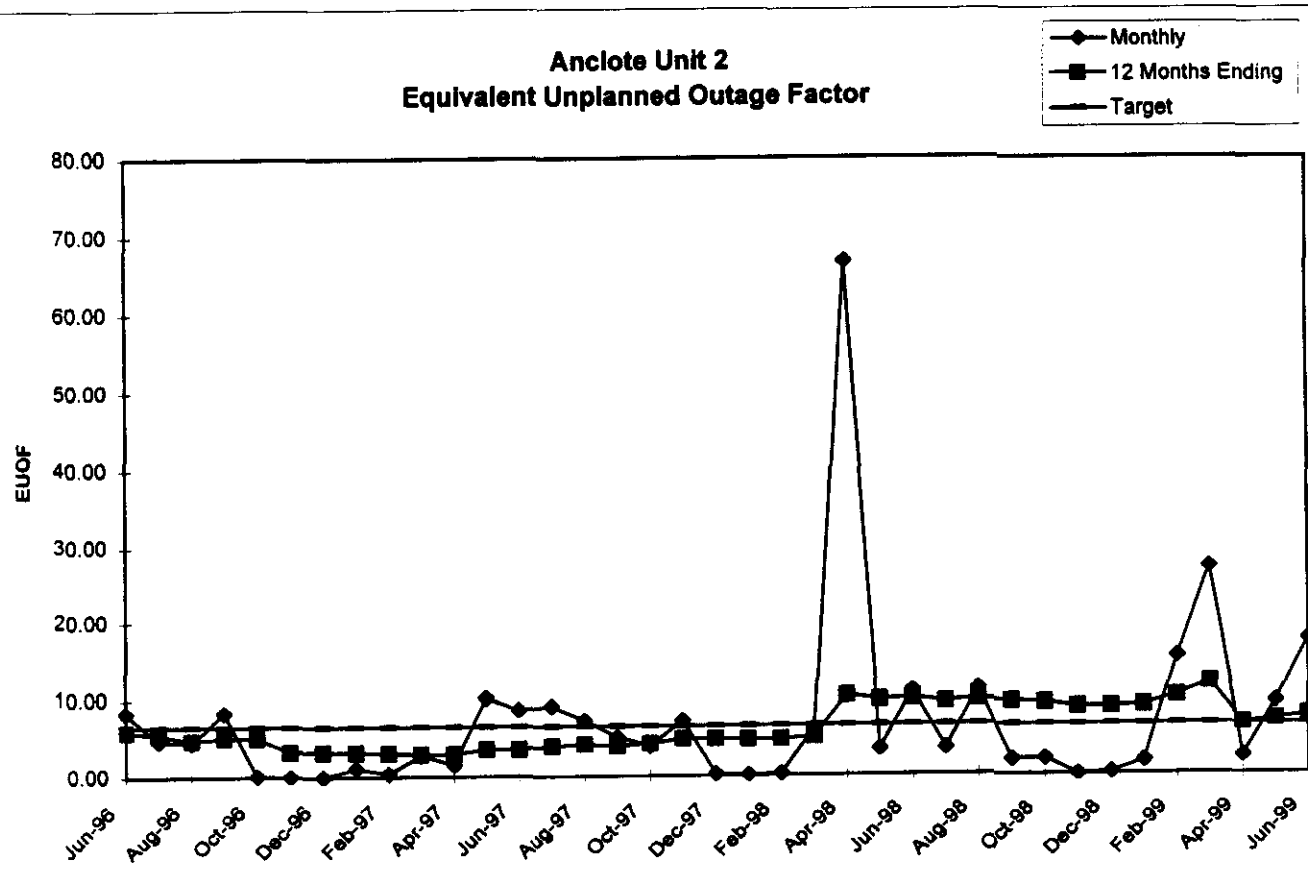
Apr-99
Jun-99


Anclote Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Anclote Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Anclote Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Bartow
Unit 3

	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	505.95	606.78	647.67	745	720	744	688.68	672	699	665.55	695.18	720	685.83	693.67	660.88	73.38	473.58	690.05
RSH	0	0	16	0	0	0	55.32	0	0	0	0	0	0	0	0	0	0	53.95
UH	238.05	137.22	56.33	0	0	0	0	0	45	53.45	48.82	0	58.17	50.33	59.12	671.62	246.42	0
POH	0	0	0	0	0	0	0	0	0	0	0	0	0	45.98	0	671.62	246.42	0
FOH	238.05	137.22	56.33	0	0	0	0	0	45	53.45	2.7	0	58.17	0	59.12	0	0	0
MOH	0	0	0	0	0	0	0	0	0	0	46.12	0	0	4.35	0	0	0	0
PFOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EFOH	223.00	0.00	0.42	0.00	0.00	0.00	66.17	68.50	0.00	0.93	0.00	1.08	93.07	178.33	22.93	73.35	15.82	0.00
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	15.75	33.25	15.22	11.47	10.37	27.38	5.25	25.92	23.00	55.08	34.73	59.85	100.95	137.95	34.02	0.00	0.00	16.92
NPC	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208

MONTHLY	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	32.00	18.44	8.00	0.00	0.00	0.00	0.00	0.00	6.05	7.43	0.39	0.00	7.82	0.00	8.21	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.22	0.00	0.00	0.62	0.00	0.00	0.00	0.00
PFOR	44.08	0.00	0.06	0.00	0.00	0.00	9.61	10.19	0.00	0.14	0.00	0.15	13.57	25.71	3.47	99.96	3.34	0.00
PMOR	3.11	5.48	2.35	1.54	1.44	3.68	0.76	3.86	3.29	8.28	5.00	8.31	14.72	19.89	5.15	0.00	0.00	2.45
EUOR	64.09	22.91	10.22	1.54	1.44	3.68	10.37	14.05	9.14	15.22	11.23	8.46	33.90	45.93	16.12	99.96	3.34	2.45
EUOF	64.09	22.91	10.00	1.54	1.44	3.68	9.60	14.05	9.14	15.22	11.23	8.46	33.90	43.10	16.12	9.85	2.20	2.27
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.18	0.00	90.15	34.23	0.00
EAF	35.91	77.09	90.00	98.46	98.56	96.32	90.40	85.95	90.86	84.78	88.77	91.54	66.10	50.72	83.88	0.00	63.58	97.73

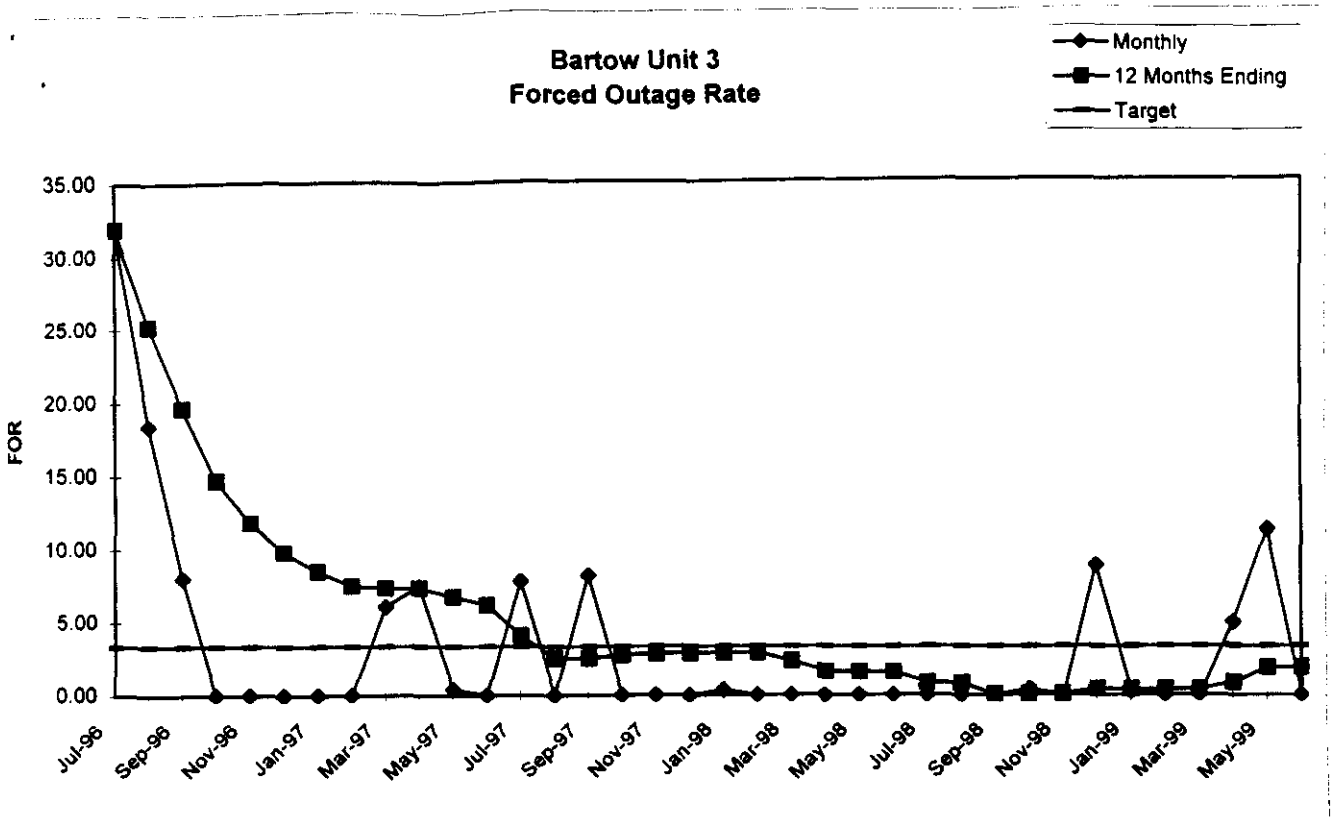
12 MONTHS	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	32.00	25.22	19.69	14.70	11.80	9.81	8.48	7.49	7.33	7.34	6.72	6.16	4.08	2.51	2.54	2.75	2.84	2.86
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.62	0.57	0.55	0.60	0.60	0.65	0.67	0.68
PFOR	44.08	20.04	12.69	8.92	6.93	5.63	6.22	6.72	5.94	5.36	4.86	4.44	2.78	4.88	5.14	6.53	6.96	7.01
PMOR	3.11	4.40	3.65	3.02	2.67	2.86	2.55	2.71	2.78	3.33	3.48	3.91	4.86	6.05	6.27	6.67	6.75	6.66
EUOR	64.09	43.50	32.81	24.88	20.26	17.46	16.50	16.22	15.41	15.39	15.00	14.46	11.87	13.67	14.16	16.12	16.71	16.69
EUOF	64.09	43.50	32.57	24.74	20.18	17.40	16.27	16.02	15.24	15.24	14.87	14.34	11.78	13.49	13.99	14.70	14.76	14.64
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.52	8.19	11.00	11.00
EAF	35.91	56.50	67.43	75.26	79.82	82.60	83.73	83.98	84.76	84.76	85.13	85.66	88.22	85.98	85.48	77.11	74.23	74.35

Bartow
Unit 3

	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744	672	744	719	744	720
SER HOURS	741.35	592.65	744	665.9	744.0	720.0	665.8	744	720	742.07	491.3	260.88	742.57	672	670.42	683.57	660.27	720
RSH	0	79.35	0	0.0	0.0	0.0	0	0	0	0	0	35.1	0	0	0	0	0	0
UH	2.65	0	0	53.1	0.0	0.0	78.25	0	0	2.93	228.7	448.02	1.43	0	73.58	35.43	83.73	0
POH	0	0	0	53.13	0	0	6.92	0	0	0	228.7	422.75	0	0	0	0	0	0
FOH	2.65	0	0	0.0	0.0	0.0	0	0	0	2.93	0	25.27	1.43	0	0	35.43	83.73	0
MOH	0	0	0	0	0	0	71.33	0	0	0	0	0	0	0	73.58	0	0	0
PFOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EFOH	80.90	5.87	0.00	0.00	0.00	0.00	20.35	0.13	11.67	1.54	0.00	0.00	0.43	5.91	2.16	0.00	1.01	0.00
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	14.10	11.93	6.62	10.38	11.79	6.66	0.00	20.27	31.64	22.98	4.59	0.00	7.86	1.43	9.40	4.07	13.62	9.56
NPC	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208	208

MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.00	8.83	0.19	0.00	0.00	4.93	11.25	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	9.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.89	0.00	0.00	0.00
PFOR	10.91	0.99	0.00	0.00	0.00	0.00	3.06	0.02	1.62	0.21	0.00	0.00	0.06	0.88	0.32	0.00	0.15	0.00
PMOR	1.90	2.01	0.89	1.56	1.58	0.93	0.00	2.72	4.39	3.10	0.93	0.00	1.06	0.21	1.40	0.60	2.06	1.33
EUOR	13.13	3.00	0.89	1.56	1.58	0.93	12.44	2.74	6.02	3.68	0.93	8.83	1.31	1.09	11.44	5.49	13.22	1.33
EUOF	13.13	2.65	0.89	1.44	1.58	0.93	12.32	2.74	6.02	3.68	0.64	3.40	1.31	1.09	11.44	5.49	13.22	1.33
POF	0.00	0.00	0.00	7.39	0.00	0.00	0.93	0.00	0.00	0.00	31.76	56.82	0.00	0.00	0.00	0.00	0.00	0.00
EAF	86.88	97.35	99.11	91.17	98.42	99.08	86.75	97.26	93.98	96.32	67.60	39.78	98.69	98.91	88.56	94.51	86.78	98.67

12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	2.87	2.90	2.31	1.62	1.58	1.58	0.82	0.82	0.03	0.07	0.07	0.39	0.38	0.37	0.38	0.82	1.88	1.88
MOR	0.67	0.68	0.67	0.67	0.06	0.06	1.00	0.94	0.93	0.86	0.86	0.90	0.90	0.89	1.82	1.81	1.83	1.83
PFOR	7.16	6.39	6.35	6.34	6.30	6.28	5.33	2.92	2.75	1.65	1.46	1.54	0.51	0.51	0.54	0.54	0.56	0.56
PMOR	6.73	6.61	6.35	5.75	5.40	4.69	3.35	1.77	1.72	1.86	1.91	1.80	1.72	1.57	1.62	1.54	1.58	1.61
EUOR	16.91	16.08	15.28	14.09	13.14	12.43	10.33	6.34	5.39	4.40	4.26	4.58	3.47	3.31	4.29	4.62	5.70	5.73
EUOF	14.94	14.07	13.37	12.24	11.42	10.80	8.97	5.54	4.71	4.18	4.06	4.15	3.15	3.03	3.92	4.26	5.24	5.28
POF	11.00	11.00	11.00	11.61	11.61	11.61	11.69	11.17	11.17	3.50	3.30	8.12	8.12	8.12	8.12	7.52	7.52	7.52
EAF	74.05	74.93	75.63	76.15	76.97	77.59	79.34	83.30	84.13	92.32	92.65	87.73	88.73	88.85	87.95	88.23	87.24	87.21


Bartow Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-96
Sep-96
Nov-96
Jan-97
Mar-97
May-97
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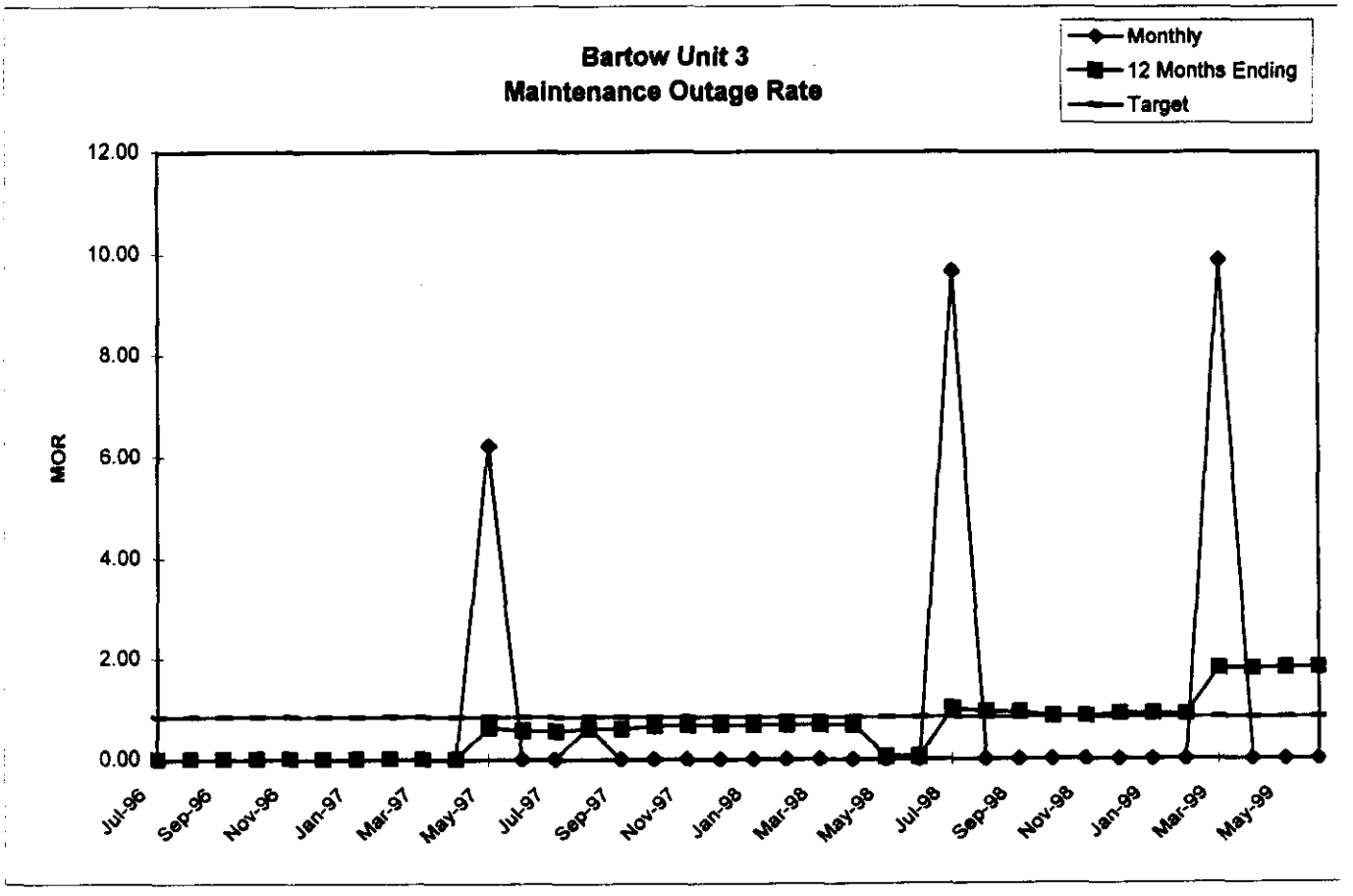
Mar-99
May-99


Bartow Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-96
Sep-96
Nov-96
Jan-97
Mar-97
May-97
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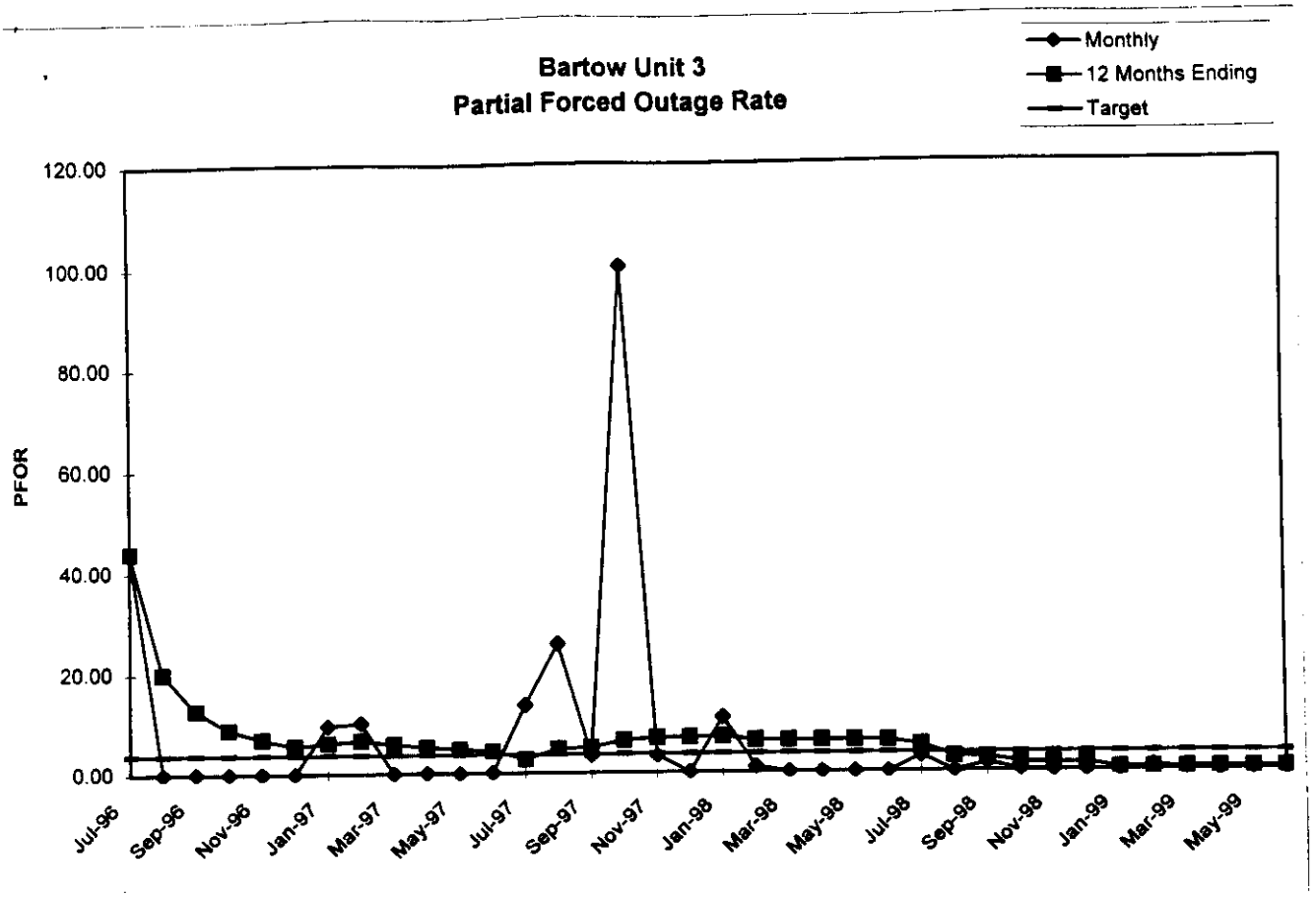
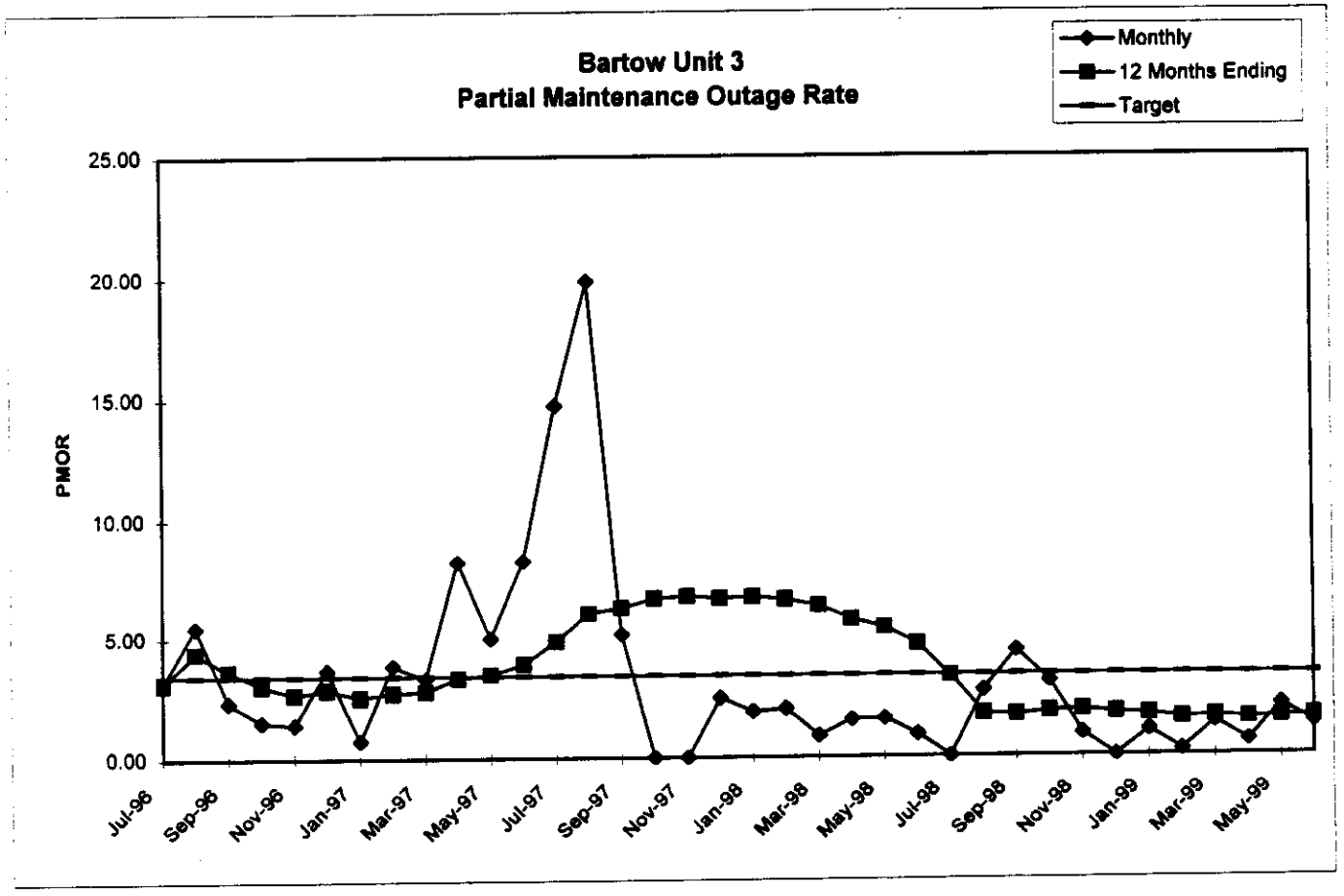
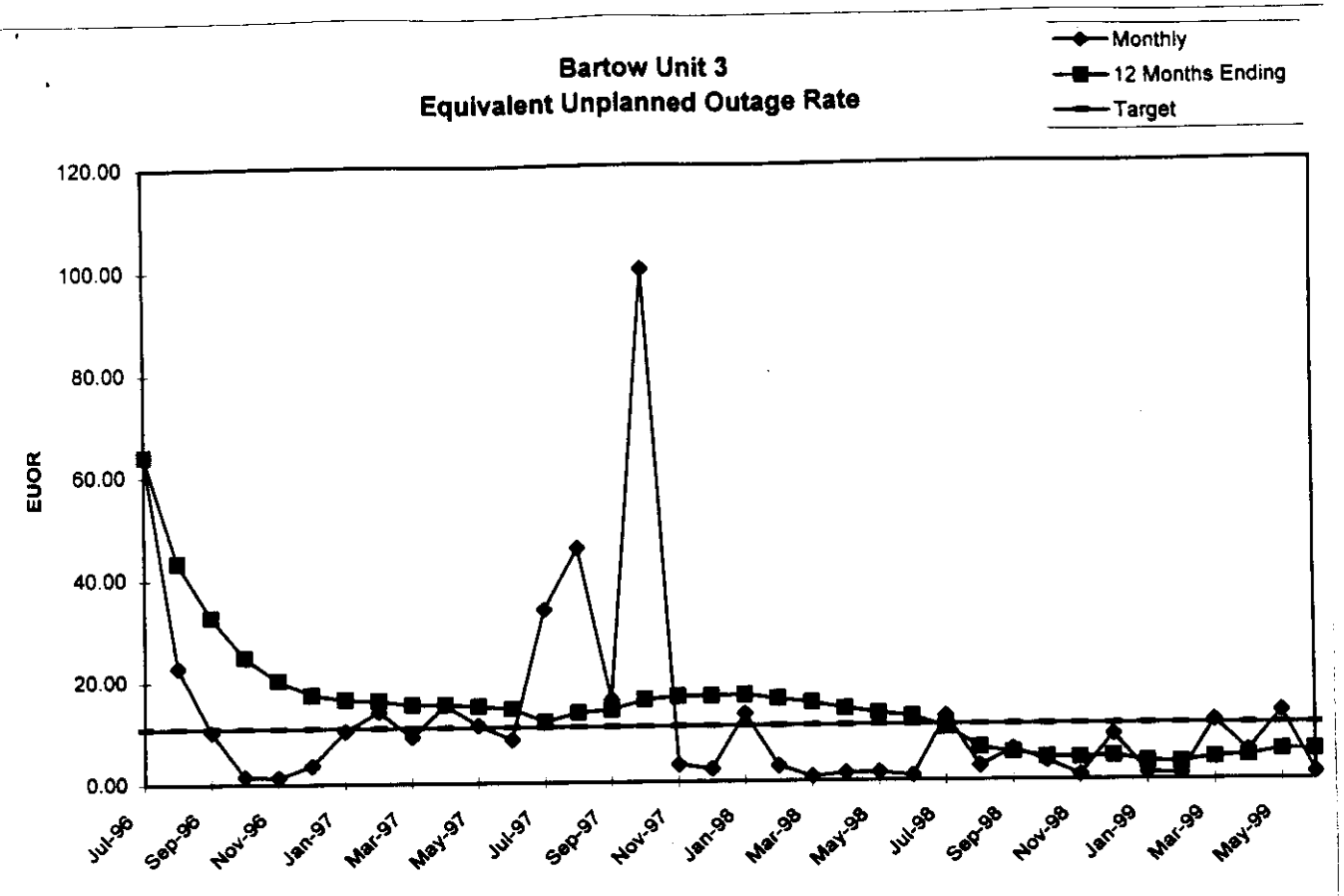
Mar-99
May-99

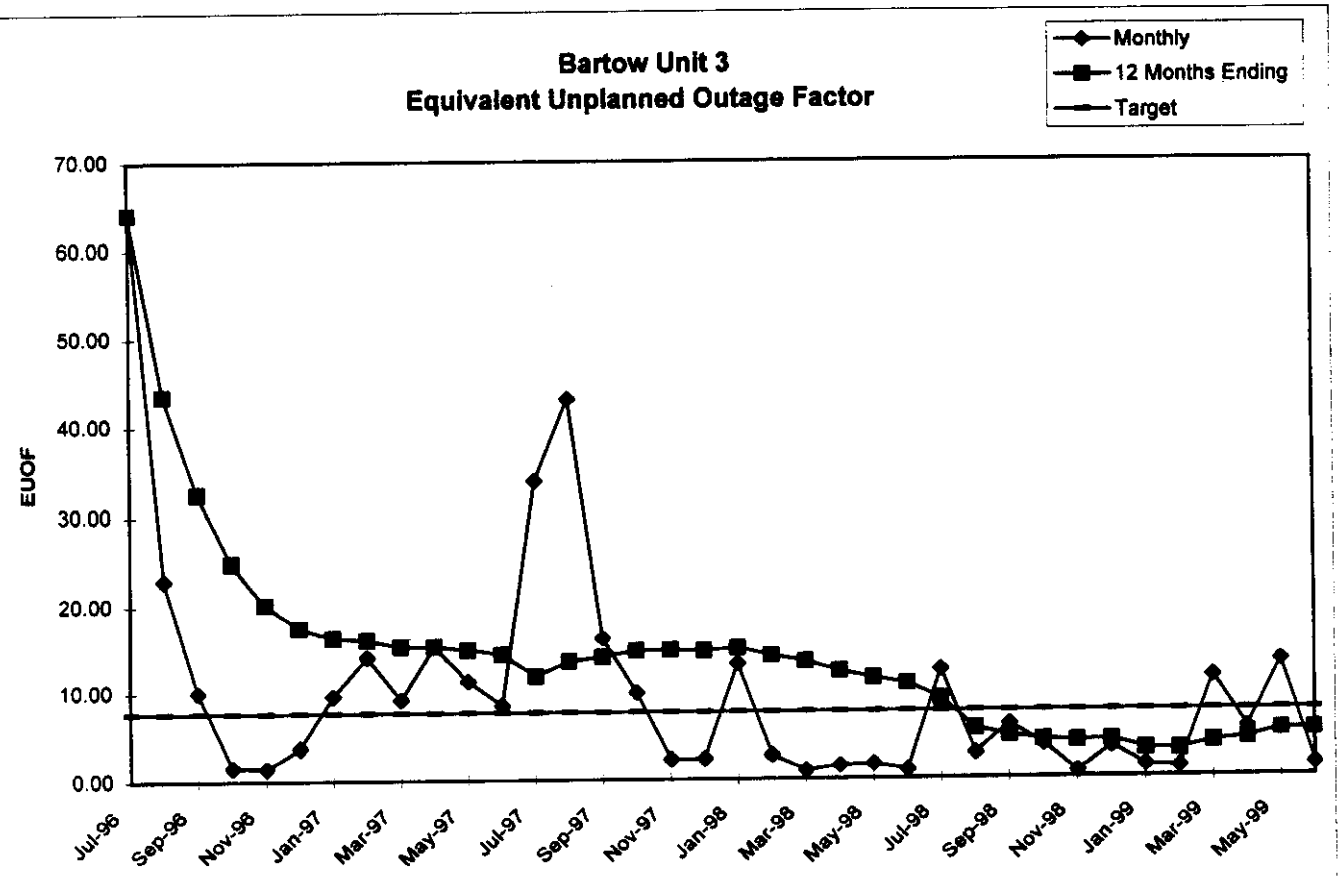

Bartow Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-96
Sep-96
Nov-96
Jan-97
Mar-97
May-97
Jul-97
Sep-97
Nov-97
Jan-98
Mar-98
May-98
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99


Bartow Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-96
Sep-96
Nov-96
Jan-97
Mar-97
May-97
Jul-97
Sep-97
Nov-97
Jan-98
Mar-98
May-98
Jul-98
Sep-98
Nov-98
Jan-99
Mar-99
May-99

Bartow Unit 3
Equivalent Unplanned Outage Rate



Bartow Unit 3
Equivalent Unplanned Outage Factor



Crystal River
UNIT 1

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	719.4	713.4	743.2	703.6	252.6	15.9	704.9	702.9	672	744	672.2	744	715.1	696.7	744	720	686.1	673.2	742.2
RSH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UH	0.6	30.6	0.8	16.4	492.4	704.1	39.1	41.1	0	0	46.8	0	4.9	47.3	0	0	58.9	46.8	1.8
POH	0	0	0	0	479.1	691.9	0	0	0	0	0	0	0	0	0	0	0	0	0
FOH	0.6	30.6	0.8	0	0	12.3	27.8	0	0	0	0.6	0	0	0	0	0	0	18	1.8
MOH	0	0	0	16.4	13.3	0	11.3	41.1	0	0	46.2	0	4.9	47.3	0	0	58.9	28.8	0
PFOH	397.3	90.3	179.8	71.6	22.7	0	201.1	198.8	77.5	184.6	28.2	36	507.4	369.9	69.5	102.9	97.1	93	77.4
LRPF	37.5	122	80.4	50.9	174	0	70.3	53.1	107.6	46.2	109.5	164.3	31.9	33.7	125.7	85.9	47.1	74.2	109.9
EFOH	40.1	29.6	38.9	9.8	10.6	0	38	28.4	22.4	22.9	8.3	15.9	43.4	33.5	23.5	23.8	12.3	18.5	22.9
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	0.08	4.11	0.11	0.00	0.00	43.62	3.79	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.24
MOR	0.00	0.00	0.00	2.28	5.00	0.00	1.58	5.52	0.00	0.00	6.43	0.00	0.68	6.36	0.00	0.00	7.91	4.10	0.00
PFOR	5.57	4.15	5.23	1.39	4.20	0.00	5.39	4.04	3.33	3.08	1.23	2.14	6.07	4.81	3.16	3.31	1.79	2.75	3.09
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	5.65	8.09	5.34	3.64	8.99	43.62	10.36	9.34	3.33	3.08	7.66	2.14	6.71	10.86	3.16	3.31	9.56	9.07	3.32
EUOF	5.65	8.09	5.34	3.64	3.21	1.71	10.36	9.34	3.33	3.08	7.66	2.14	6.71	10.86	3.16	3.31	9.56	9.07	3.32
POF	0.00	0.00	0.00	0.00	64.31	96.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	94.35	91.91	94.66	96.36	32.48	2.19	89.64	90.66	96.67	96.92	92.34	97.86	93.29	89.14	96.84	96.69	90.44	90.93	96.68

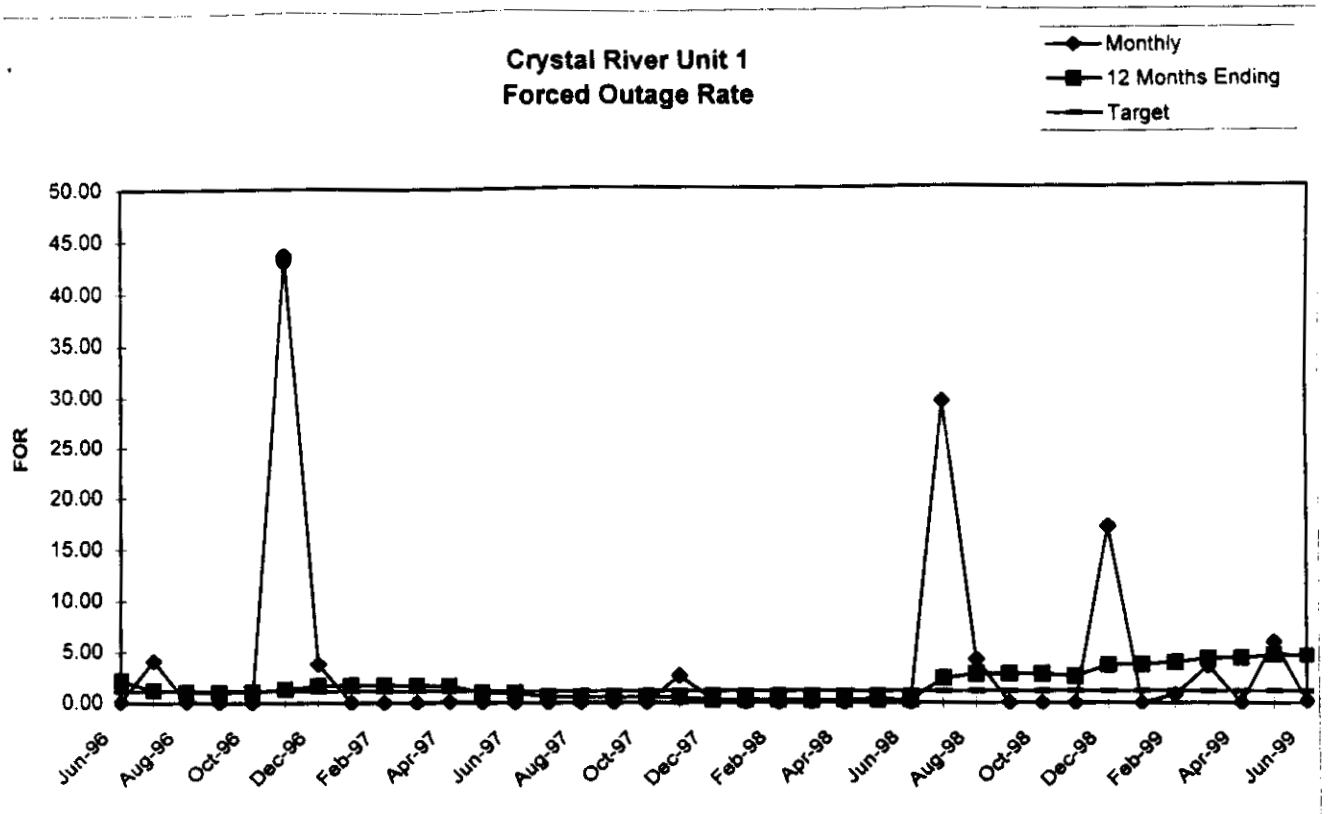
12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	2.20	1.23	1.01	1.01	1.07	1.31	1.69	1.70	1.71	1.70	1.66	0.97	0.97	0.56	0.55	0.55	0.52	0.54	0.24
MOR	6.49	6.43	6.42	6.60	7.15	4.38	4.55	5.10	5.12	4.67	2.02	1.71	1.77	2.39	2.39	2.17	2.61	2.74	2.60
PFOR	3.53	3.64	3.57	3.31	3.19	3.32	3.62	3.74	3.64	3.88	3.82	3.59	3.63	3.69	3.48	3.67	3.48	3.43	3.24
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	11.65	10.87	10.61	10.54	11.01	8.71	9.49	10.12	10.05	9.86	7.29	6.14	6.24	6.51	6.30	6.27	6.48	6.57	5.97
EUOF	11.65	10.87	10.61	10.54	10.41	7.55	8.22	8.77	8.71	8.54	6.32	5.32	5.41	5.64	5.46	5.43	5.97	6.57	5.97
POF	0.00	0.00	0.00	0.00	5.45	13.33	13.33	13.33	13.37	13.37	13.37	13.37	13.37	13.37	13.37	13.37	7.90	0.00	0.00
EAF	88.35	89.13	89.39	89.46	84.13	79.12	78.45	77.90	77.93	78.09	80.32	81.31	81.23	80.99	81.18	81.20	86.13	93.43	94.03

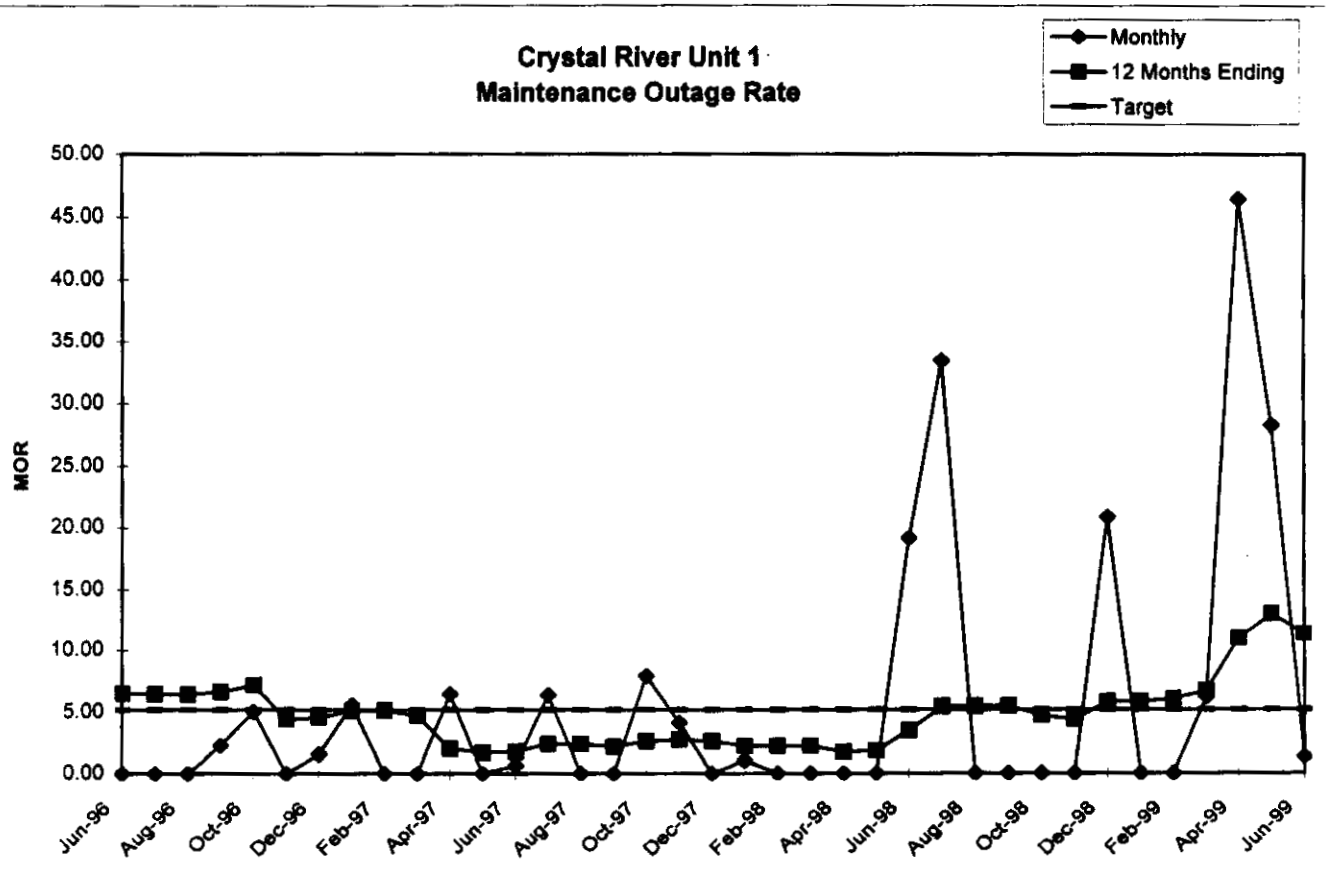
Crystal River
UNIT 1

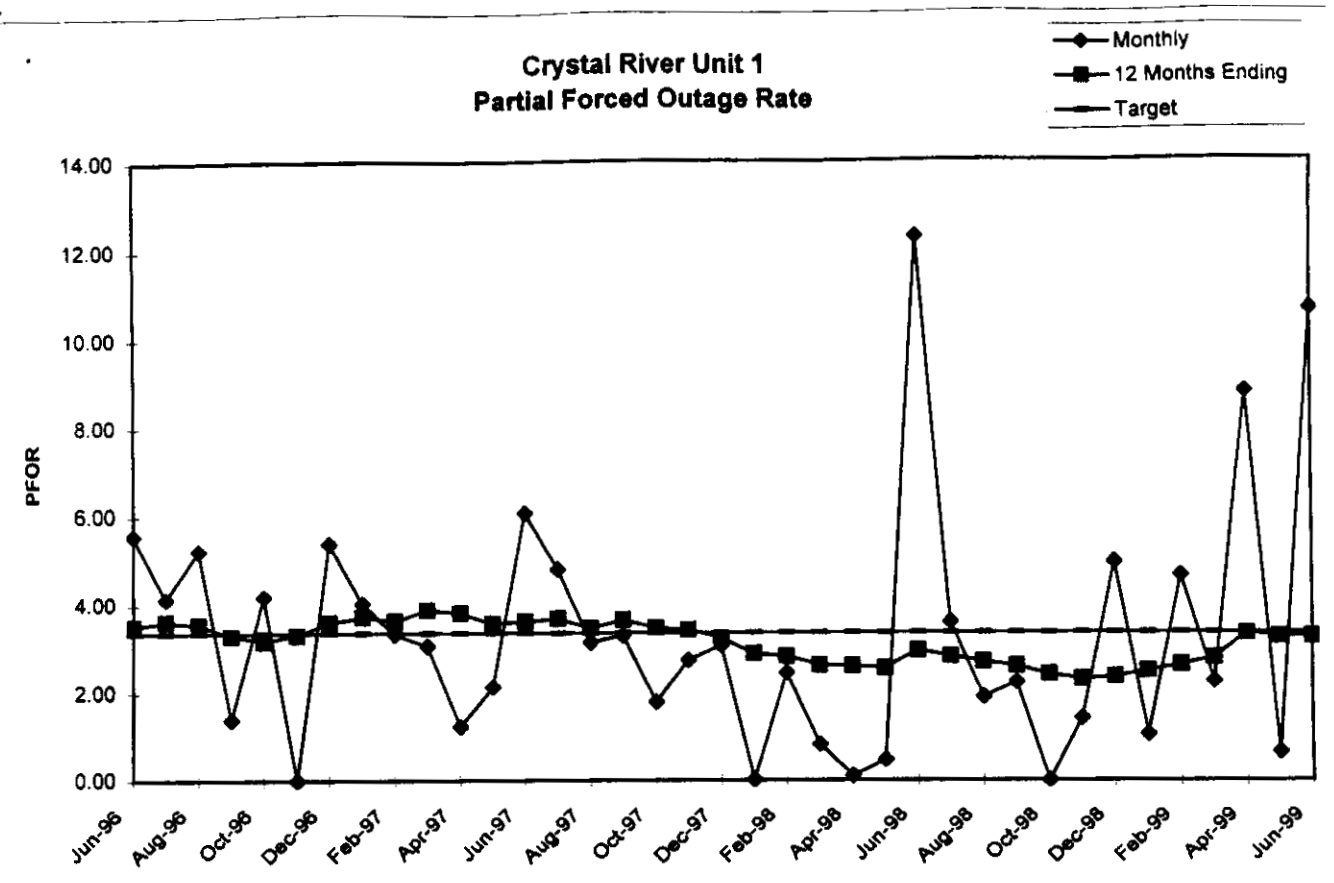
	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744.0	672.0	744.0	719.0	744.0	720.0
SER HOURS	736.1	672	744	457.0	320.3	582.0	386.9	712.5	720	745.0	613.8	353.2	594.1	404.3	674.2	385.2	510.2	709.4
RSH	0	0	0	0	0	0	0	0	0	0.0	106.2	224.7	149.9	264.4	0.0	0.0	0.0	0.0
UH	7.9	0	0	262.0	423.8	138.0	357.1	31.5	0	0.0	0.0	166.2	0.0	3.3	69.8	333.8	233.8	10.6
POH	0	0	0	262.0	422.0	0.0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FOH	0	0	0	0.0	1.7	0.0	162.3	31.5	0	0.0	0.0	72.9	0.0	3.3	25.2	0.0	32.2	1.2
MOH	7.9	0	0	0.0	0.0	138.0	194.8	0	0	0.0	0.0	93.4	0.0	0.0	44.6	333.8	201.6	9.4
PFOH	0.6	163.1	122.3	4.3	3.0	273.6	138.6	46.6	49.5	0.0	8.7	85.3	101.6	375.8	148.5	115.4	22.8	263.9
LRPF	93.6	37.6	18.6	40.5	186.0	97.3	37.4	108.1	121.2	0.0	371.9	76.3	22.8	18.6	38.1	109.2	53.7	106.6
EFOH	0.1	16.5	6.1	0.46	1.50	71.58	13.93	13.54	16.13	0.00	8.72	17.50	6.23	18.79	15.21	33.86	3.29	75.64
PMOH	5	27.6	62.9	5.0	0.0	13.1	0	8.6	46.2	0.0	79.1	0.0	2.3	0.0	5.5	0.0	7.2	24.9
LRPM	186	164.1	149.2	186.0	0.0	66.6	0	155.7	137	0.0	372.0	0.0	48.4	0.0	74.5	0.0	14.0	167.4
EMOH	2.5	12.2	25.2	2.50	0.00	2.34	0.00	3.60	17.01	0.00	79.05	0.00	0.30	0.00	1.11	0.00	0.27	11.18
NPC	372	372	372	372	372	372	372	372	372	372	372	372	372.0	372.0	372.0	372.0	372.0	372.0

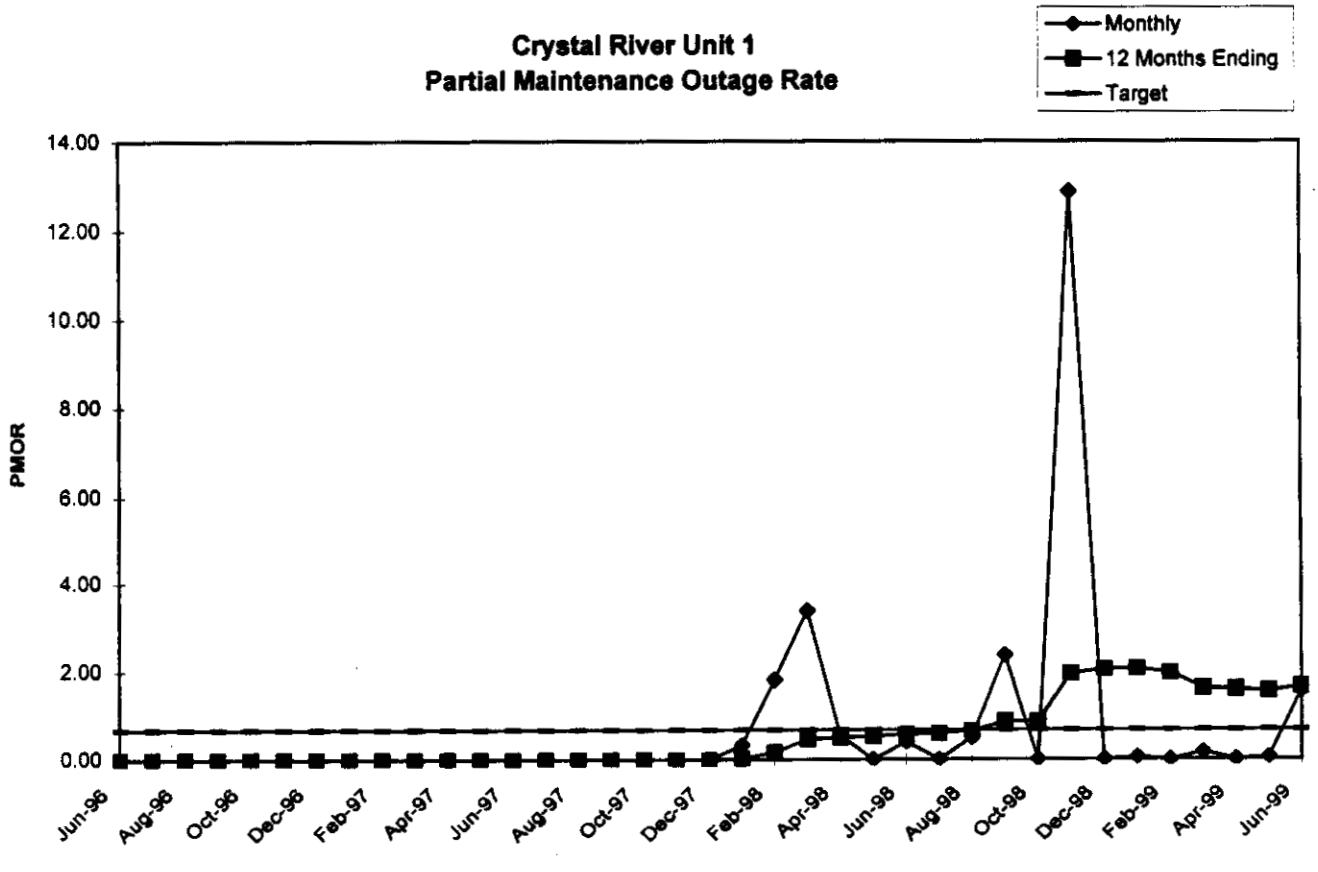
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.00	0.00	0.00	0.00	0.53	0.00	29.55	4.23	0.00	0.00	0.00	17.10	0.00	0.82	3.61	0.00	5.93	0.17
MOR	1.06	0.00	0.00	0.00	0.00	19.16	33.49	0.00	0.00	0.00	0.00	20.91	0.00	0.00	6.20	46.43	28.32	1.31
PFOR	0.01	2.46	0.82	0.10	0.47	12.30	3.60	1.90	2.24	0.00	1.42	4.95	1.05	4.65	2.26	8.79	0.65	10.66
PMOR	0.34	1.82	3.39	0.55	0.00	0.40	0.00	0.51	2.36	0.00	12.68	0.00	0.05	0.00	0.16	0.00	0.05	1.58
EUOR	1.41	4.27	4.21	0.65	1.00	29.43	49.87	6.54	4.60	0.00	14.30	35.37	1.10	5.43	11.58	51.13	31.90	13.53
EUOF	1.41	4.27	4.21	0.41	0.43	29.43	49.87	6.54	4.60	0.00	12.19	24.69	0.88	3.29	11.58	51.13	31.90	13.53
POF	0.00	0.00	0.00	36.44	56.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.59	95.73	95.79	63.15	42.84	70.57	50.13	93.46	95.40	100.00	87.81	75.31	99.12	96.71	88.42	48.87	68.10	86.47

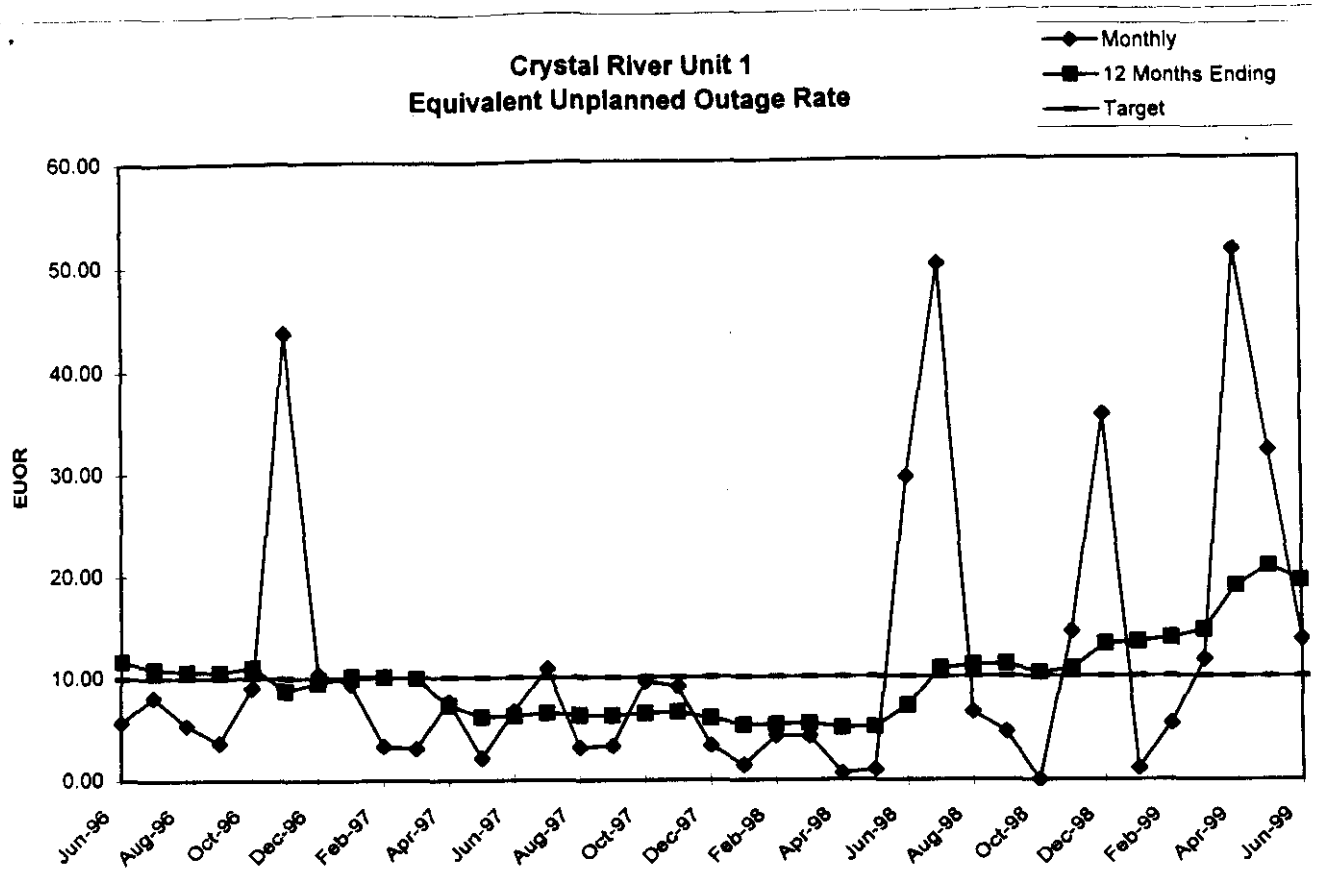
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.24	0.24	0.24	0.24	0.27	0.28	2.40	2.82	2.82	2.79	2.59	3.67	3.74	3.93	4.33	4.37	4.67	4.60
MOR	2.22	2.22	2.22	1.74	1.84	3.49	5.43	5.45	5.45	4.70	4.38	5.80	5.82	6.04	6.69	11.03	13.09	11.42
PFOR	2.90	2.83	2.63	2.60	2.56	2.97	2.83	2.71	2.60	2.42	2.31	2.36	2.50	2.63	2.80	3.34	3.27	3.27
PMOR	0.03	0.17	0.47	0.51	0.54	0.58	0.60	0.65	0.88	0.87	1.94	2.05	2.06	1.96	1.61	1.59	1.55	1.65
EUOR	5.30	5.37	5.47	5.02	5.13	7.16	10.75	11.06	11.18	10.29	10.71	13.08	13.28	13.67	14.42	18.73	20.66	19.23
EUOF	5.30	5.37	5.47	4.87	4.73	6.60	9.91	10.20	10.30	9.49	9.75	11.56	11.52	11.44	12.07	16.23	18.90	17.60
POF	0.00	0.00	0.00	2.99	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	7.81	4.82	0.00	0.00
EAF	94.70	94.63	94.53	92.14	87.46	85.60	82.28	81.99	81.89	82.70	82.44	80.63	80.67	80.75	80.12	78.95	81.10	82.40

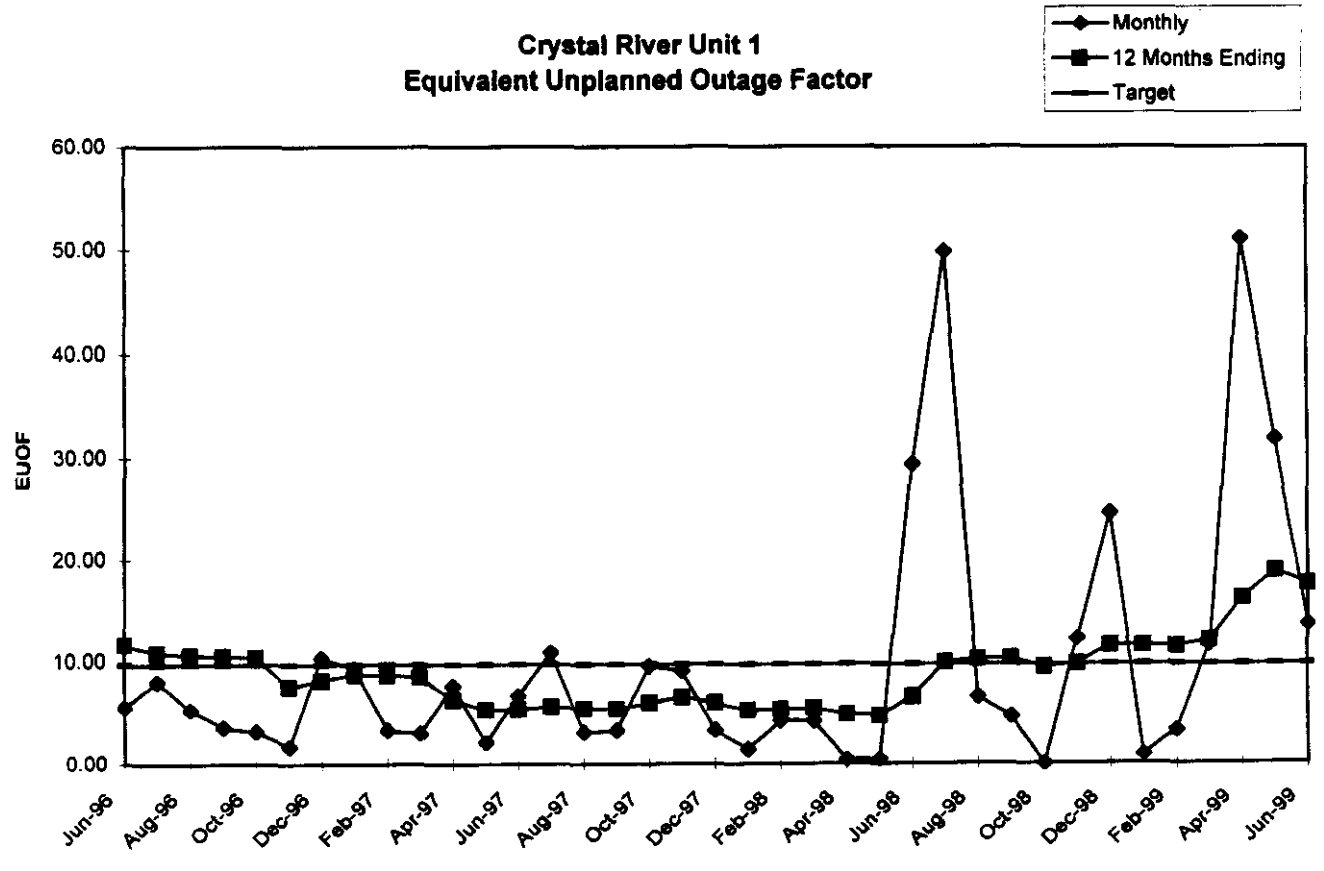

Crystal River Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Crystal River
UNIT 2

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98
PER HOUR	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744	744
SER HOUR	707.7	744	744	718.7	617.5	563.6	741.6	616.9	672	0.7	615.8	644.4	720	744	635.4	639.5	745	588.7	597.8	652.9
RSH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UH	12.3	0	0	1.3	127.5	156.4	2.4	127.1	0	743.3	103.3	99.6	0	0	108.6	80.5	0	131.3	146.2	91.1
POH	0	0	0	0	125.2	0	0	0	0	743.3	98.5	0	0	0	12.4	0	0	0	0	0
FOH	12.3	0	0	1.3	2.4	114.7	2.4	63	0	0	4.8	2.8	0	0	96.2	68.2	0	0	3.5	85.6
MOH	0	0	0	0	0	41.8	0	64.1	0	0	0	96.8	0	0	0	12.3	0	131.3	142.7	5.5
PFOH	138	147.6	116.3	64.5	401.2	14.8	59.7	85.9	18.5	0	9.9	128.5	44.4	79.8	102.3	110.1	133.8	297	245.5	238.6
LRPF	119.1	167.2	197.5	208.6	39	174.2	181.9	149.9	200	0	150.5	66.7	218.3	168.4	153.9	129.8	111.9	104	90.3	72.6
EFOH	35.1	52.7	49.1	28.7	33.4	5.5	23.2	27.5	7.9	0	3.2	18.3	20.7	28.7	33.6	30.5	32	66	47.4	37
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	33.3
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	93.6
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6.7
NPC	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468	468

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98
FOR	1.71	0.00	0.00	0.18	0.39	16.91	0.32	9.27	0.00	0.00	0.77	0.43	0.00	0.00	13.15	9.64	0.00	0.00	0.58	11.59
MOR	0.00	0.00	0.00	0.00	0.00	6.90	0.00	9.41	0.00	0.00	0.00	13.06	0.00	0.00	0.00	1.89	0.00	18.24	19.27	0.84
PFOR	4.96	7.08	6.60	3.99	5.41	0.98	3.13	4.46	1.18	0.00	0.52	2.84	2.88	3.86	5.29	4.77	4.30	11.21	7.93	5.67
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.03
EUOR	6.58	7.08	6.60	4.17	5.78	22.50	3.44	20.78	1.18	0.00	1.29	15.85	2.88	3.86	17.74	15.42	4.30	27.40	26.02	18.12
EUOF	6.58	7.08	6.60	4.17	4.81	22.50	3.44	20.78	1.18	0.00	1.11	15.85	2.88	3.86	17.45	15.42	4.30	27.40	26.02	18.12
POF	0.00	0.00	0.00	0.00	16.81	0.00	0.00	0.00	0.00	99.91	13.70	0.00	0.00	0.00	1.67	0.00	0.00	0.00	0.00	0.00
EAF	93.42	92.92	93.40	95.83	78.39	77.50	96.56	79.22	98.82	0.09	85.19	84.15	97.13	96.14	80.89	84.58	95.70	72.60	73.98	81.88

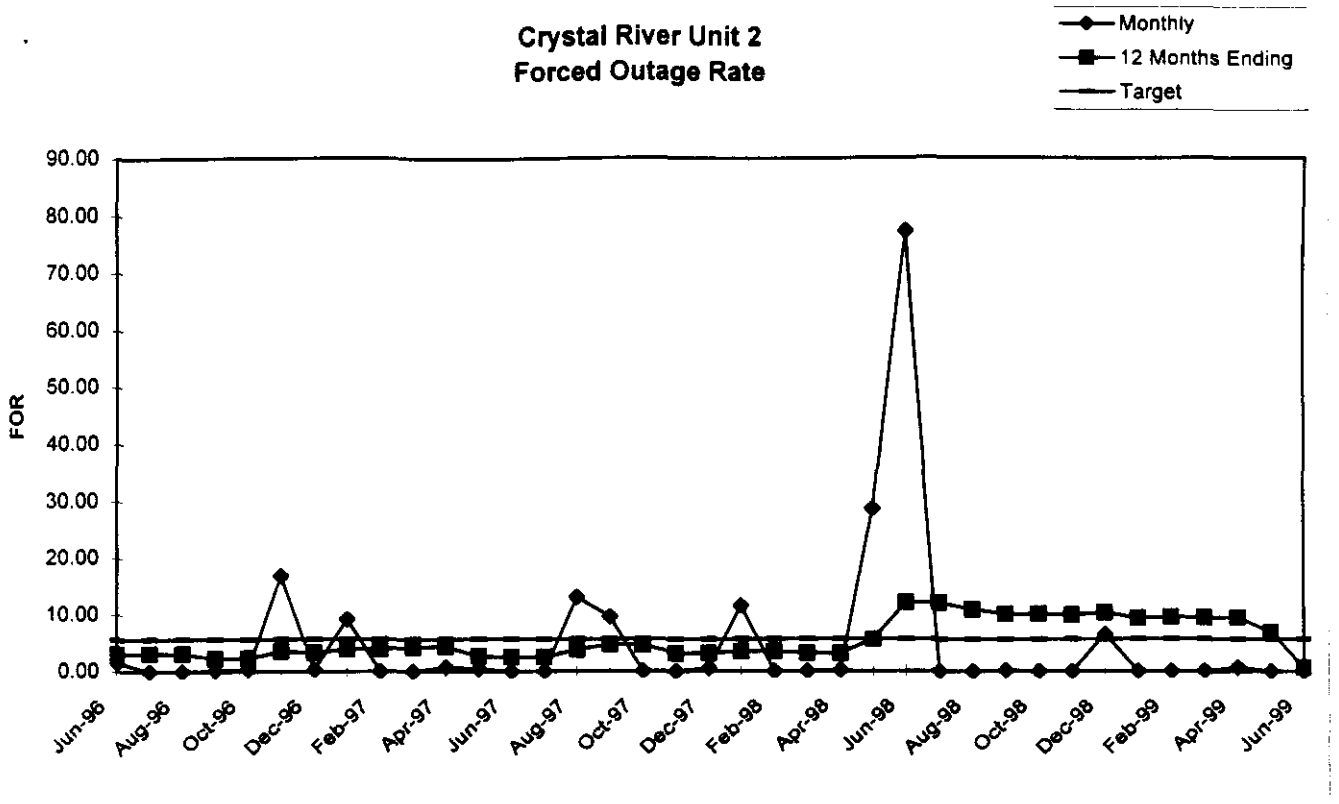
12 MONTH	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98
FOR	3.15	3.15	3.15	2.29	2.33	3.58	3.28	3.92	3.93	4.26	4.33	2.68	2.52	2.52	3.80	4.69	4.58	3.12	3.20	3.47
MOR	1.31	1.31	1.31	1.30	1.30	1.74	1.63	1.68	1.68	1.40	1.42	2.67	2.67	2.67	2.71	2.90	2.85	3.97	5.83	5.08
PFOR	2.46	2.98	2.94	3.32	3.58	3.39	3.37	3.61	3.72	3.82	3.88	3.85	3.65	3.33	3.16	3.22	3.15	3.96	4.37	4.48
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
EUOR	6.74	7.23	7.19	6.73	7.02	8.40	8.02	8.88	9.00	9.15	9.29	8.87	8.52	8.22	9.27	10.31	10.10	10.54	12.67	12.42
EUOF	5.67	6.08	6.05	5.66	5.88	7.73	7.82	8.76	8.87	8.25	8.26	7.89	7.58	7.31	8.23	9.16	9.11	9.51	11.43	11.21
POF	14.77	14.77	14.77	14.77	15.10	6.91	1.43	1.43	1.43	9.91	11.04	11.04	11.04	11.04	11.18	11.18	9.75	9.75	9.75	9.75
EAF	79.56	79.15	79.18	79.57	79.01	85.37	90.76	89.82	89.70	81.84	80.70	81.07	81.38	81.65	80.59	79.66	81.14	80.73	78.82	79.04

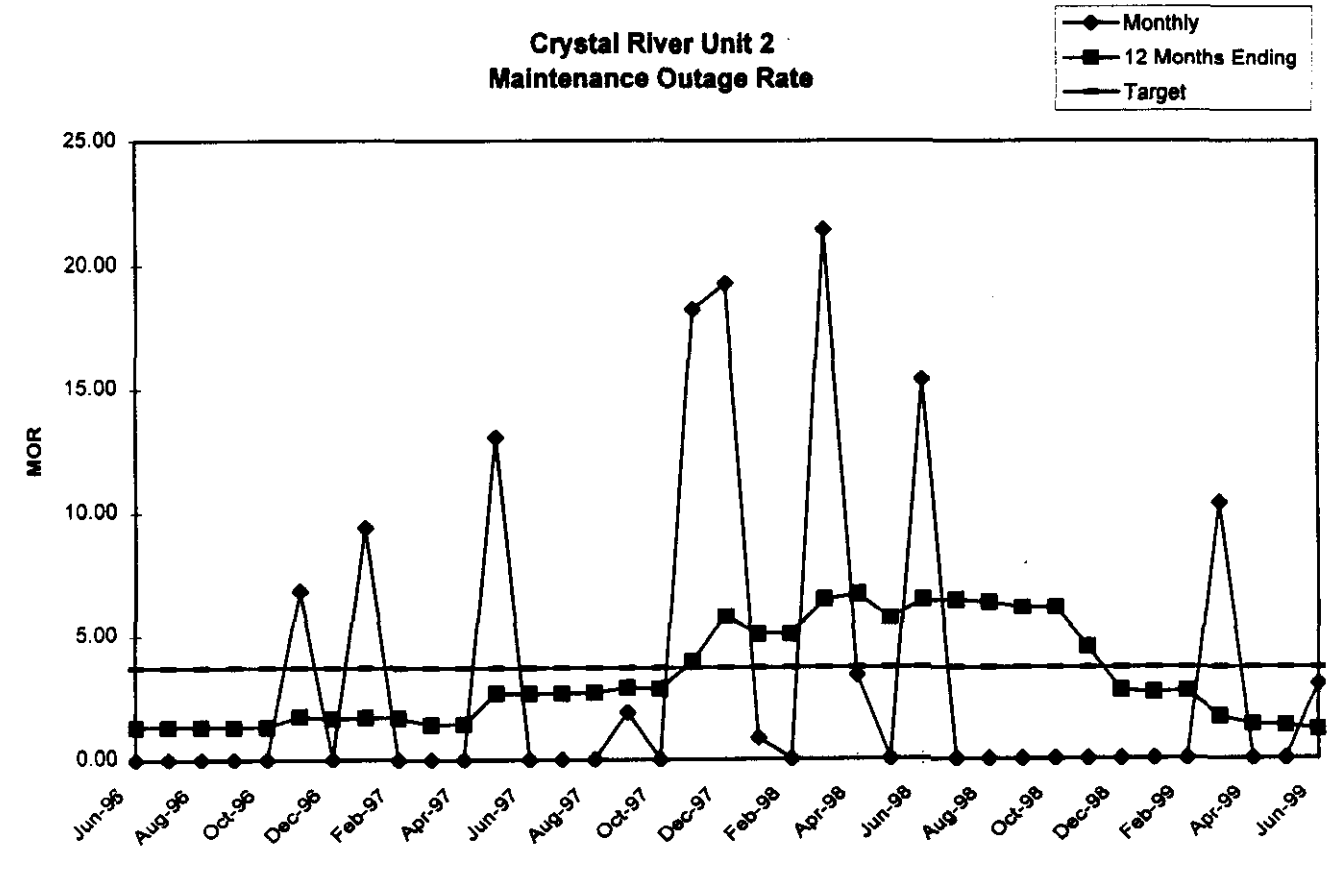
Crystal Riv
UNIT 2

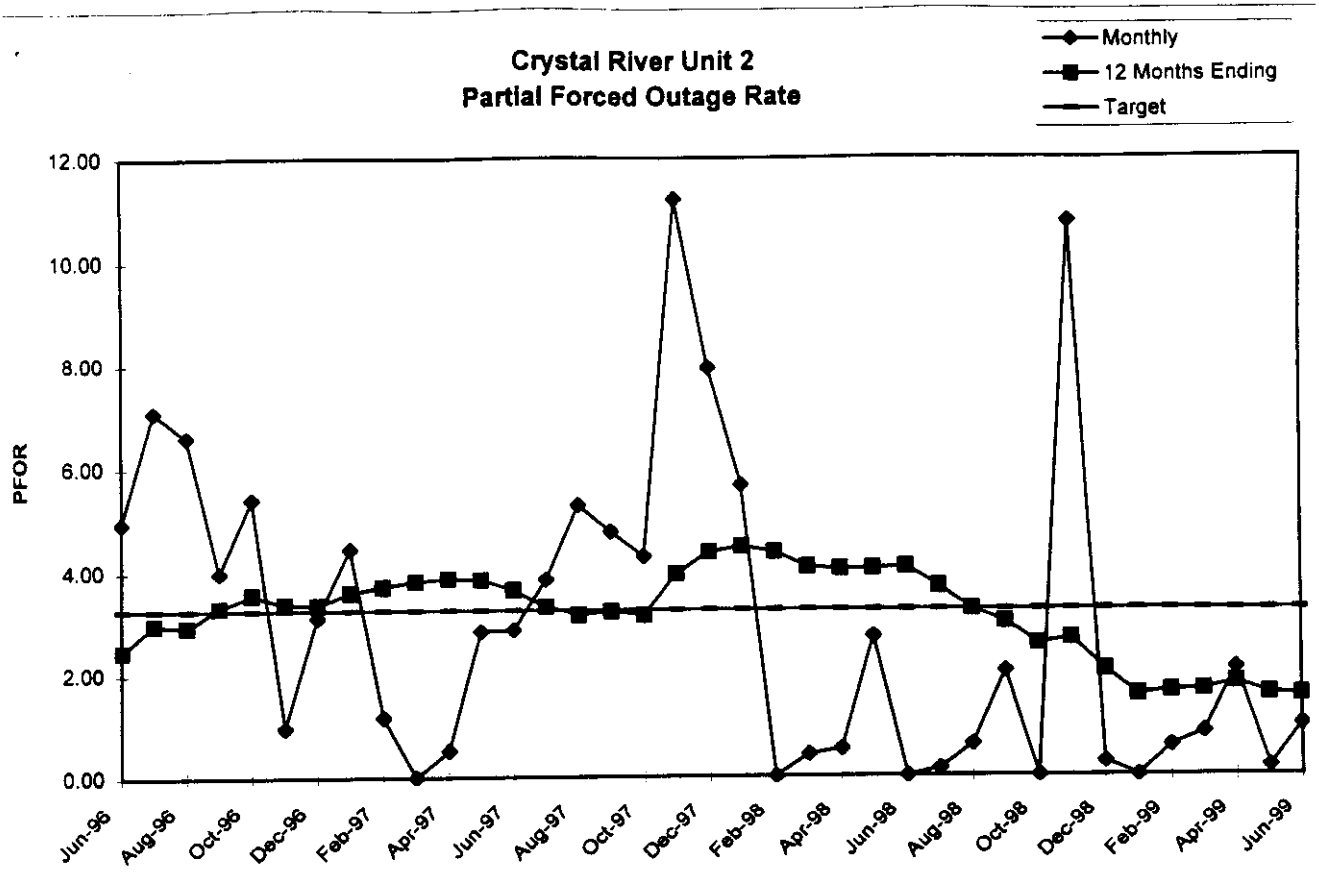
	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOUR	672	744	719	744	720	744	744	720	745	720	744	744.00	672.00	744.00	719.00	744.00	720.00
SER HOUR	672	584.6	693.5	530.0	157.0	744	744	718.8	745.0	720.0	695.2	660.33	550.53	666.70	713.75	744.00	698.27
RSH	0	0	0	0	0	0	0	0	0.0	0.0	0.0	83.67	121.47	0.00	0.00	0.00	0.00
UH	0	159.4	25.5	214.1	563.0	0	0	1.2	0.0	0.0	48.8	0.00	0.00	77.30	5.25	0.00	21.73
POH	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0	0	1.2	214.1	534.6	0	0	1.2	0.0	0.0	48.8	0.00	0.00	0.00	5.25	0.00	0.00
MOH	0	159.4	24.3	0.0	28.5	0	0	0	0.0	0.0	0.0	0.00	0.00	77.30	0.00	0.00	21.73
PFOH	0	82.3	251.8	494.8	0.0	16.6	107.3	56.9	0.0	81.3	7.5	0.00	50.65	20.20	39.65	6.35	25.43
LRPF	0	14.5	6.9	13.7	0.0	29.5	20	120.5	0.0	446.4	117.1	0.00	29.34	131.50	176.47	93.60	129.32
EFOH	0	2.5	3.69	14.44	0.00	1.05	4.59	14.65	0.00	77.53	1.87	0.00	3.16	5.64	14.82	1.26	6.94
PMOH	46.6	0	28.9	16.0	0.0	37.4	0	49.3	0.0	3.0	52.8	0.00	0.00	0.00	0.00	44.75	22.90
LRPM	234	0	206.9	234.0	0.0	93.6	0	219	0.0	468.0	79.5	0.00	0.00	0.00	0.00	108.92	152.99
EMOH	23.3	0	12.77	7.98	0.00	7.48	0.00	23.07	0.00	3.00	8.98	0.00	0.00	0.00	0.00	10.30	7.39
NPC	468	468	468	468	468	468	468	468	468	468	468	469.00	470.00	471.00	472.00	473.00	474.00

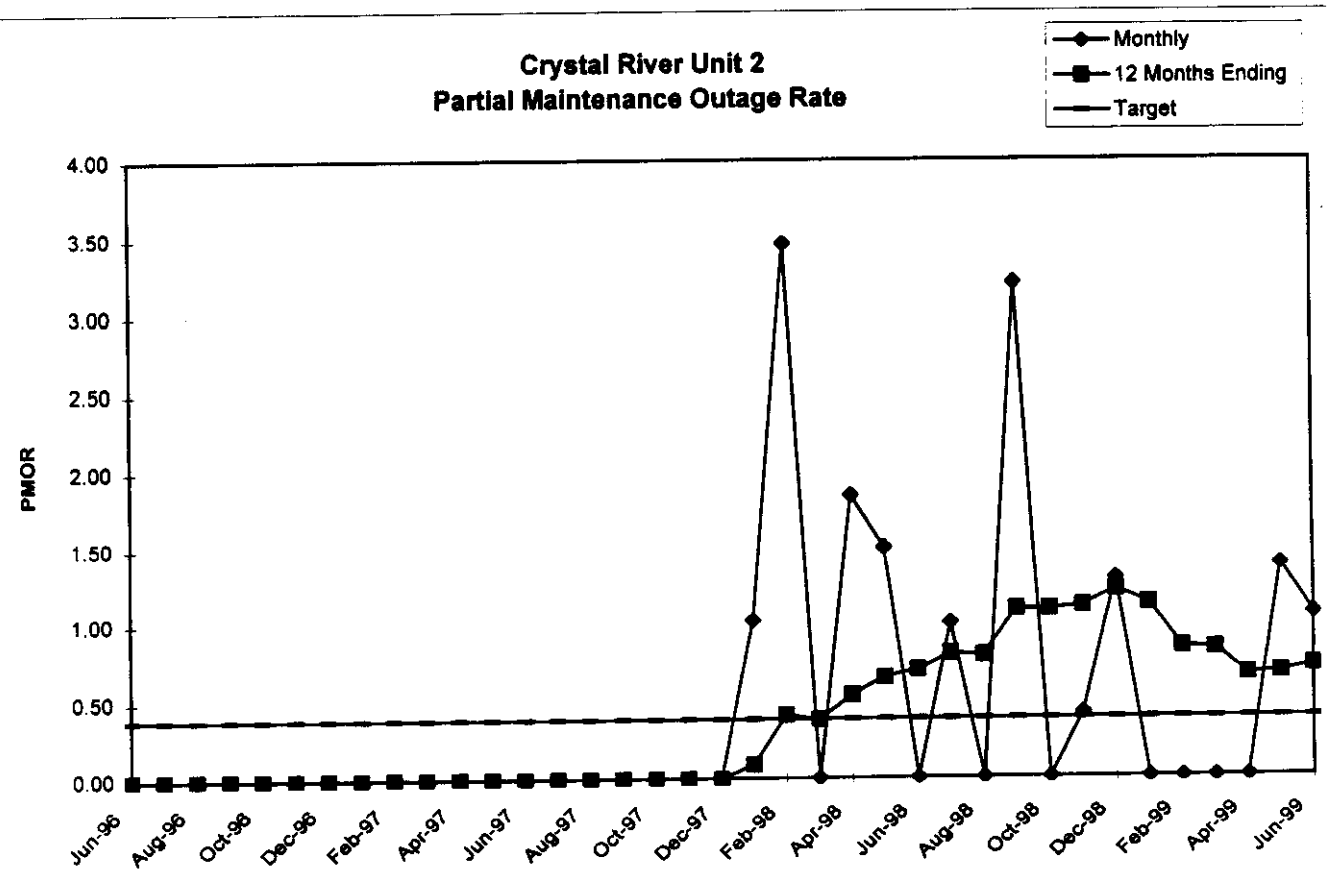
MONTHLY	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.00	0.00	0.18	28.77	77.30	0.00	0.00	0.17	0.00	0.00	6.56	0.00	0.00	0.00	0.73	0.00	0.00
MOR	0.00	21.42	3.38	0.00	15.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.39	0.00	0.00	3.02
PFOR	0.00	0.43	0.53	2.73	0.00	0.14	0.62	2.04	0.00	10.77	0.27	0.00	0.57	0.85	2.08	0.17	0.99
PMOR	3.47	0.00	1.84	1.51	0.00	1.01	0.00	3.21	0.00	0.42	1.29	0.00	0.00	0.00	0.00	1.39	1.06
EUOR	3.47	21.76	5.84	31.78	78.20	1.15	0.62	5.41	0.00	11.19	8.01	0.00	0.57	11.15	2.79	1.55	5.01
EUOF	3.47	21.76	5.84	31.78	78.20	1.15	0.62	5.41	0.00	11.19	8.01	0.00	0.47	11.15	2.79	1.55	5.01
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	96.53	78.24	94.16	68.22	21.80	98.85	99.38	94.59	100.00	88.81	91.99	100.00	99.53	88.85	97.21	98.45	94.99

12 MONTH	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	3.47	3.22	3.15	5.67	12.17	12.17	10.99	10.16	10.16	10.00	10.36	9.45	9.59	9.49	9.51	6.98	0.65
MOR	5.08	6.53	6.74	5.74	6.51	6.51	6.42	6.21	6.21	4.55	2.76	2.69	2.74	1.68	1.36	1.33	1.17
PFOR	4.37	4.08	4.05	4.06	4.09	3.70	3.25	3.01	2.58	2.68	2.05	1.57	1.64	1.66	1.80	1.58	1.57
PMOR	0.41	0.38	0.54	0.65	0.70	0.80	0.79	1.09	1.09	1.12	1.22	1.13	0.84	0.83	0.66	0.67	0.72
EUOR	12.61	13.40	13.64	14.99	21.19	20.96	19.50	18.68	18.32	16.98	15.45	14.05	14.01	13.09	12.83	10.20	4.04
EUOF	11.38	13.23	13.62	14.97	21.16	20.93	19.50	18.68	18.32	16.98	15.45	13.91	13.68	12.78	12.53	9.97	3.95
POF	9.75	1.27	0.14	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	78.87	85.50	86.24	84.89	78.70	78.93	80.50	81.32	81.68	83.02	84.55	86.09	86.32	87.22	87.47	90.03	96.05

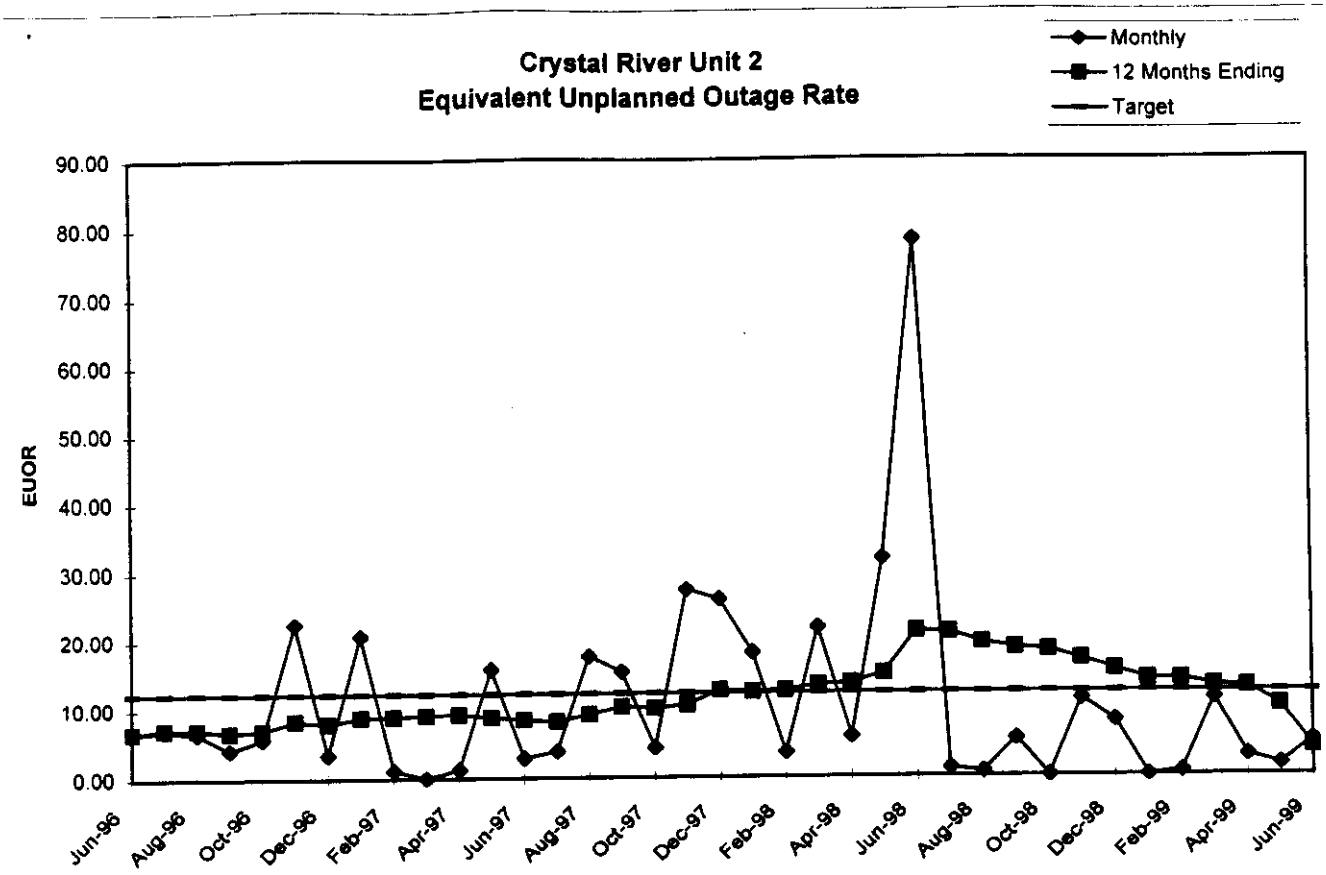

Crystal River Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

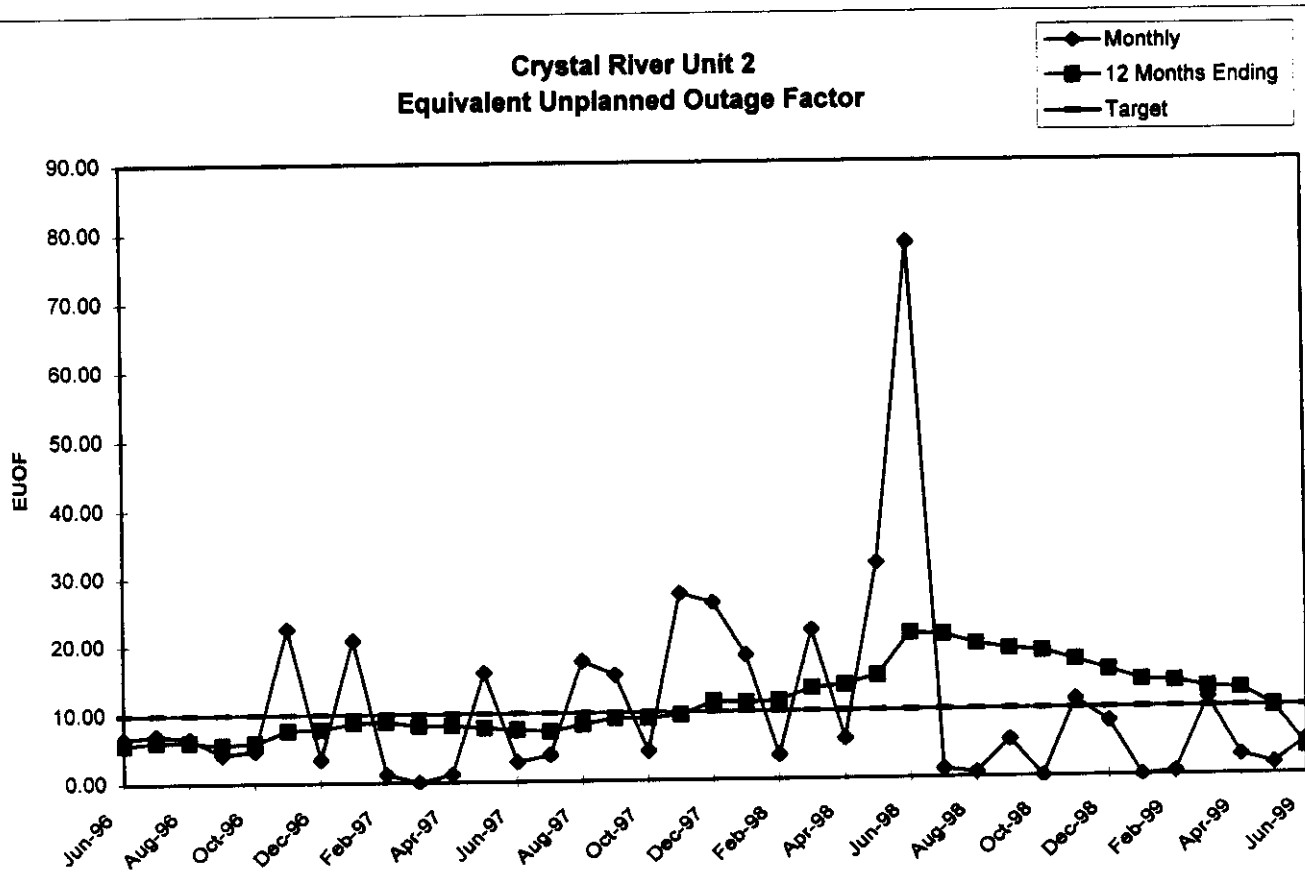

Crystal River Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Crystal River Unit 2
Equivalent Unplanned Outage Rate



Crystal River Unit 2
Equivalent Unplanned Outage Factor



Crystal River
UNIT 3

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	585.6	744	744	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UH	134.4	0	0	386	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
POH	0	0	0	289	0	0	0	0	0	0	0	0	0	0	0	0	745	720	744
FOH	134.4	0	0	386	745	720	744	744	672	744	719	744	720	744	744	720	0	0	0
MOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PFOH	210.7	16.8	290	16.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPF	219.1	12.4	248	315.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EFOH	62.2	0.3	96.8	6.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	742.6	742.6	742.6	742.6	740	740	740	740	740	740	740	740	740	740	740	740	743	743	743

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	18.67	0.00	0.00	89.56	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	10.62	0.04	13.01	15.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	27.31	0.04	13.01	91.14	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00	0.00	0.00
EUOF	27.31	0.04	13.01	54.56	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	0.00	0.00	0.00
POF	0.00	0.00	0.00	40.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	100.00	100.00
EAF	72.69	99.96	86.99	5.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

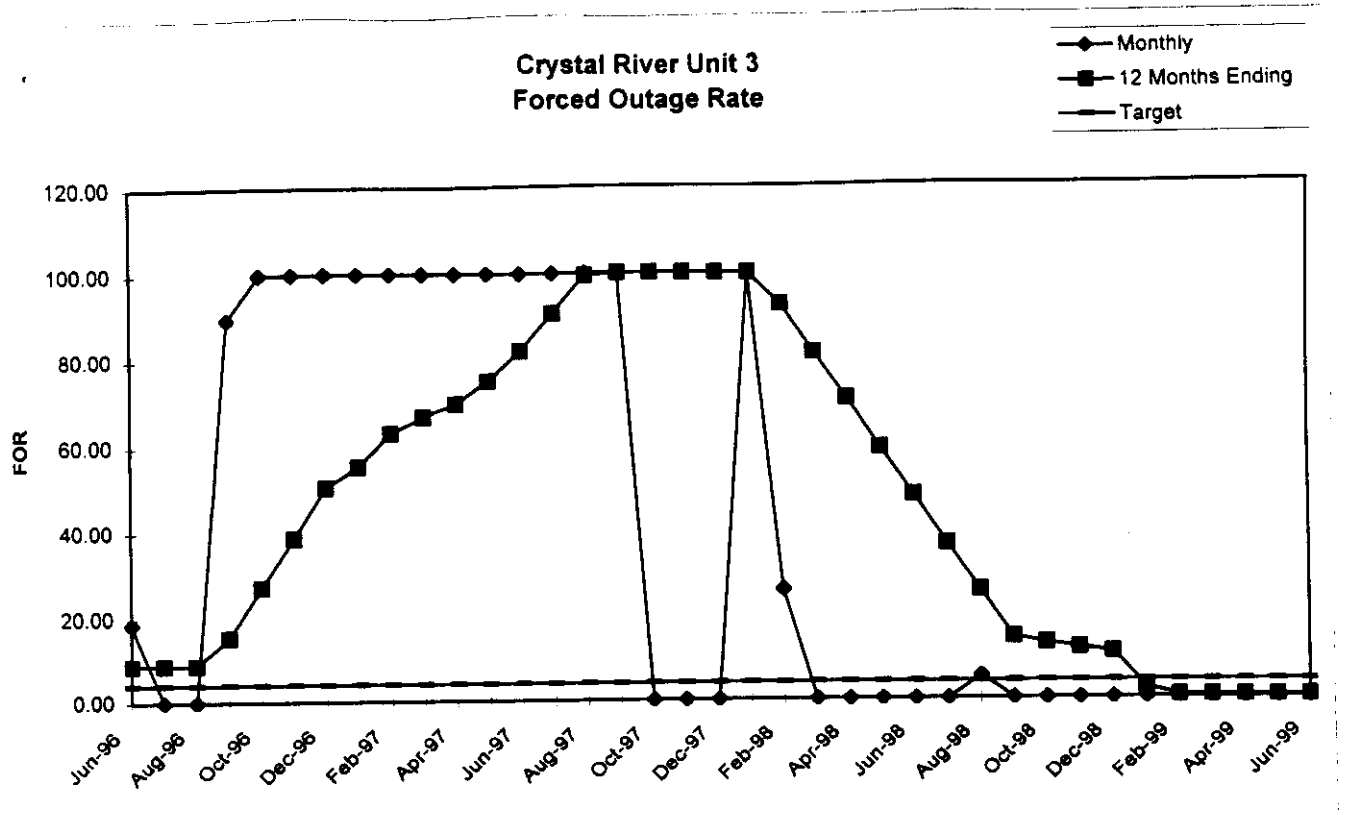
12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	8.92	8.92	8.92	15.50	27.28	38.73	50.56	55.27	63.03	66.79	69.76	74.99	81.90	90.69	99.47	100.00	100.00	100.00	100.00
MOR	0.82	0.82	0.82	0.93	0.50	0.59	0.73	0.81	0.94	0.94	0.94	0.00	0.00	0.00	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
PFOR	3.66	3.55	4.84	5.34	5.79	6.85	8.49	8.84	10.22	10.22	10.22	7.84	6.78	13.13	15.11	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
EUOR	12.91	12.81	13.98	20.64	31.74	43.13	54.92	59.37	66.93	70.28	72.93	76.95	83.13	91.91	99.55	100.00	100.00	100.00	100.00
EUOF	9.70	9.63	10.51	14.63	22.81	30.99	39.46	42.66	50.45	58.95	67.15	74.41	80.39	88.88	96.26	100.00	91.50	83.28	74.78
POF	24.85	24.85	24.85	28.14	28.14	28.14	28.14	28.14	24.62	16.12	7.92	3.30	3.30	3.30	3.30	0.00	8.50	16.72	25.22
EAF	65.45	65.52	64.64	57.03	49.05	40.86	32.39	29.19	24.93	24.93	24.93	22.29	16.31	7.82	0.44	0.00	0.00	0.00	0.00

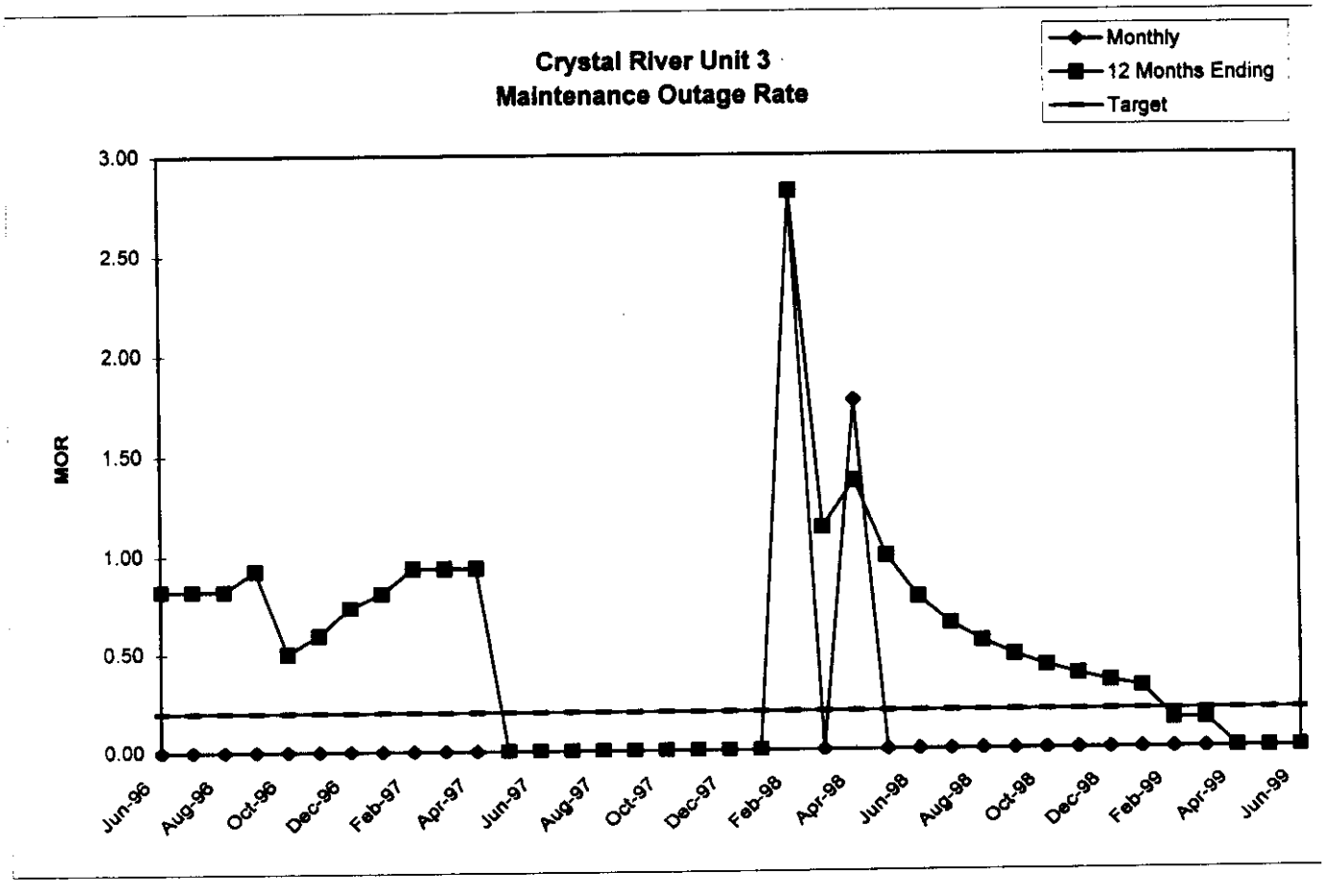
Crystal River
UNIT 3

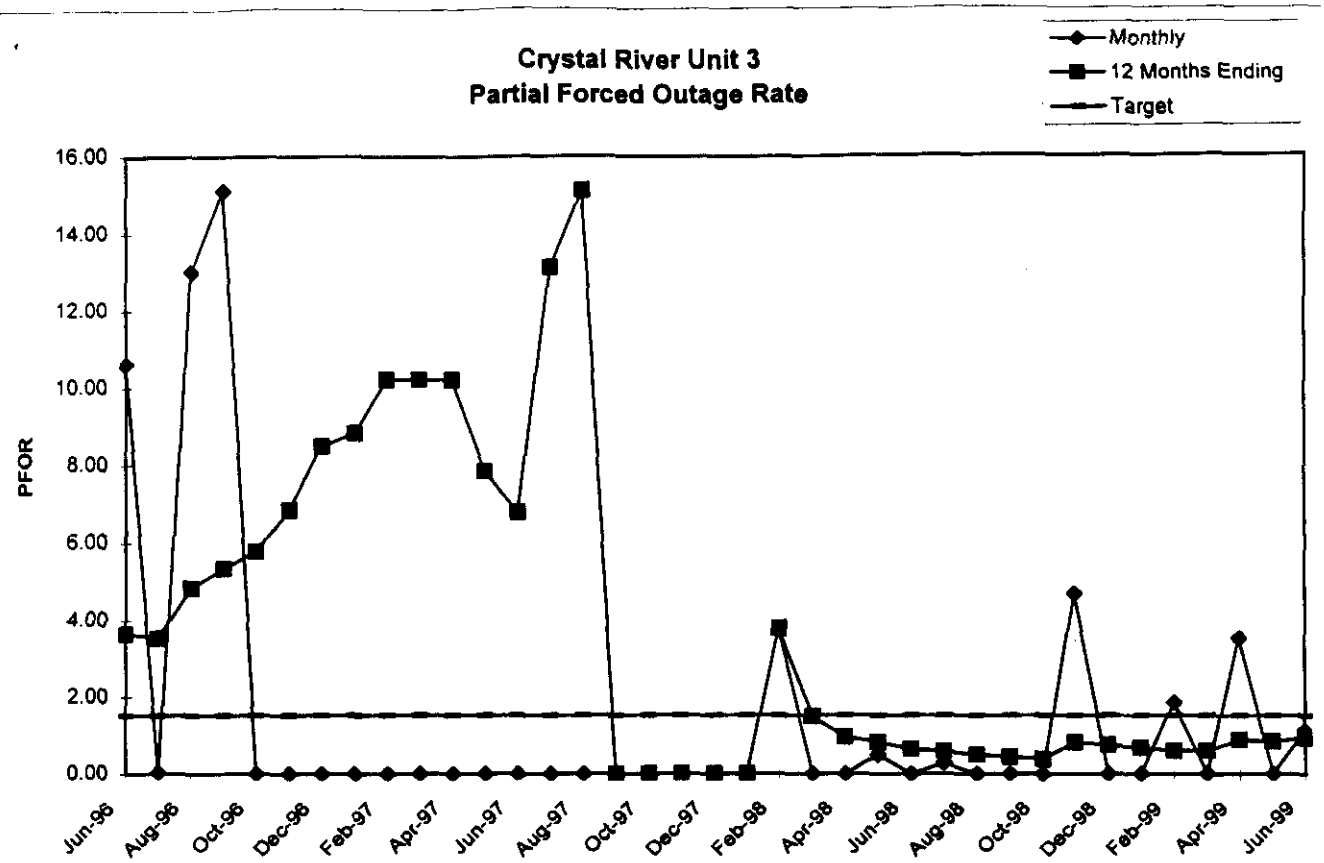
	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	0	486.4	744	706.3	744.0	720.0	744	704.5	720	745.0	720.0	744.0	744.00	672.00	744.00	719.00	744.00	720.00
RSH	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
UH	744	185.6	0	12.7	0.0	0.0	0	39.5	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
POH	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
FOH	744	171.5	0	0.0	0.0	0.0	0	39.5	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0	14.1	0	12.7	0.0	0.0	0	0	0	0.0	0.0	0.0	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0	44.4	2.2	0.0	30.2	0.0	79.6	0	0	0.0	29.3	0.0	3.13	467.32	0.00	51.50	0.00	38.00
LRPF	0	307.2	3.9	0.0	89.2	0.0	19.5	0	0	0.0	852.4	0.0	17.67	19.77	0.00	366.43	0.00	157.93
EFOH	0	18.4	0.01	0.00	3.63	0.00	2.09	0.00	0.00	0.00	33.65	0.00	0.07	12.43	0.00	25.40	0.00	8.08
PMOH	0	104	0	72.4	0.0	3.0	71.2	20.9	0	3.3	0.0	10.9	2.75	21.17	0.00	30.00	48.75	38.00
LRPM	0	335.9	0	201.6	0.0	9.1	113.4	227.9	0	48.6	0.0	47.5	18.65	421.89	0.00	10.87	111.54	41.46
EMOH	0	47	0.00	19.65	0.00	0.04	10.87	6.41	0.00	0.22	0.00	0.70	0.07	12.02	0.00	0.44	7.32	2.12
NPC	743	743	743	743	743	743	743	743	743	743	743	743	743	743	743	743	743	743

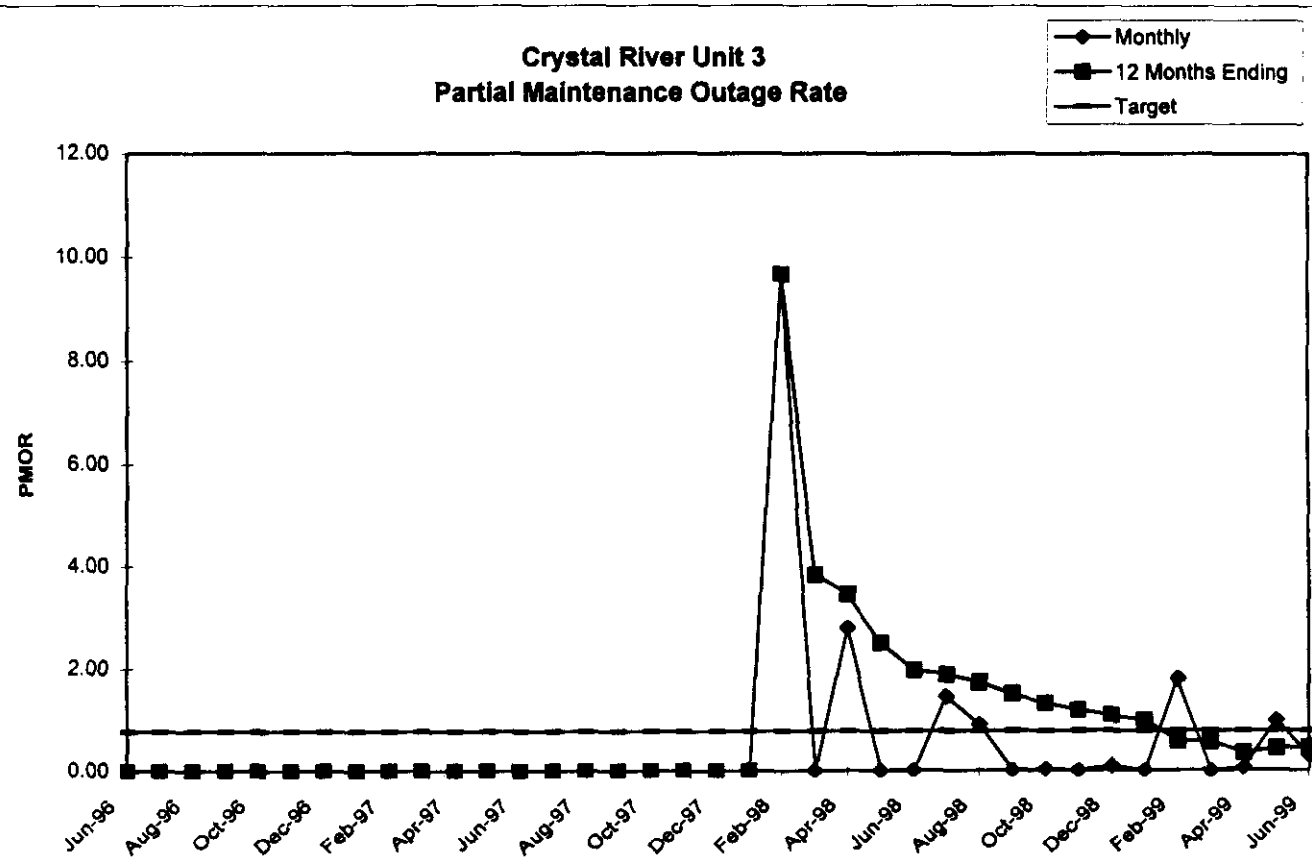
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	100.00	26.07	0.00	0.00	0.00	0.00	0.00	5.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	2.82	0.00	1.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	3.78	0.00	0.00	0.49	0.00	0.28	0.00	0.00	0.00	4.67	0.00	0.01	1.85	0.00	3.53	0.00	1.12
PMOR	0.00	9.66	0.00	2.78	0.00	0.01	1.46	0.91	0.00	0.03	0.00	0.09	0.01	1.79	0.00	0.06	0.98	0.29
EUOR	100.00	37.35	0.00	4.50	0.49	0.01	1.74	6.17	0.00	0.03	4.67	0.09	0.02	3.64	0.00	3.59	0.98	1.42
EUOF	100.00	37.35	0.00	4.50	0.49	0.01	1.74	6.17	0.00	0.03	4.67	0.09	0.02	3.64	0.00	3.59	0.98	1.42
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	0.00	62.65	100.00	95.50	99.51	99.99	98.26	93.83	100.00	99.97	95.33	99.91	99.98	96.36	100.00	96.41	99.02	98.58

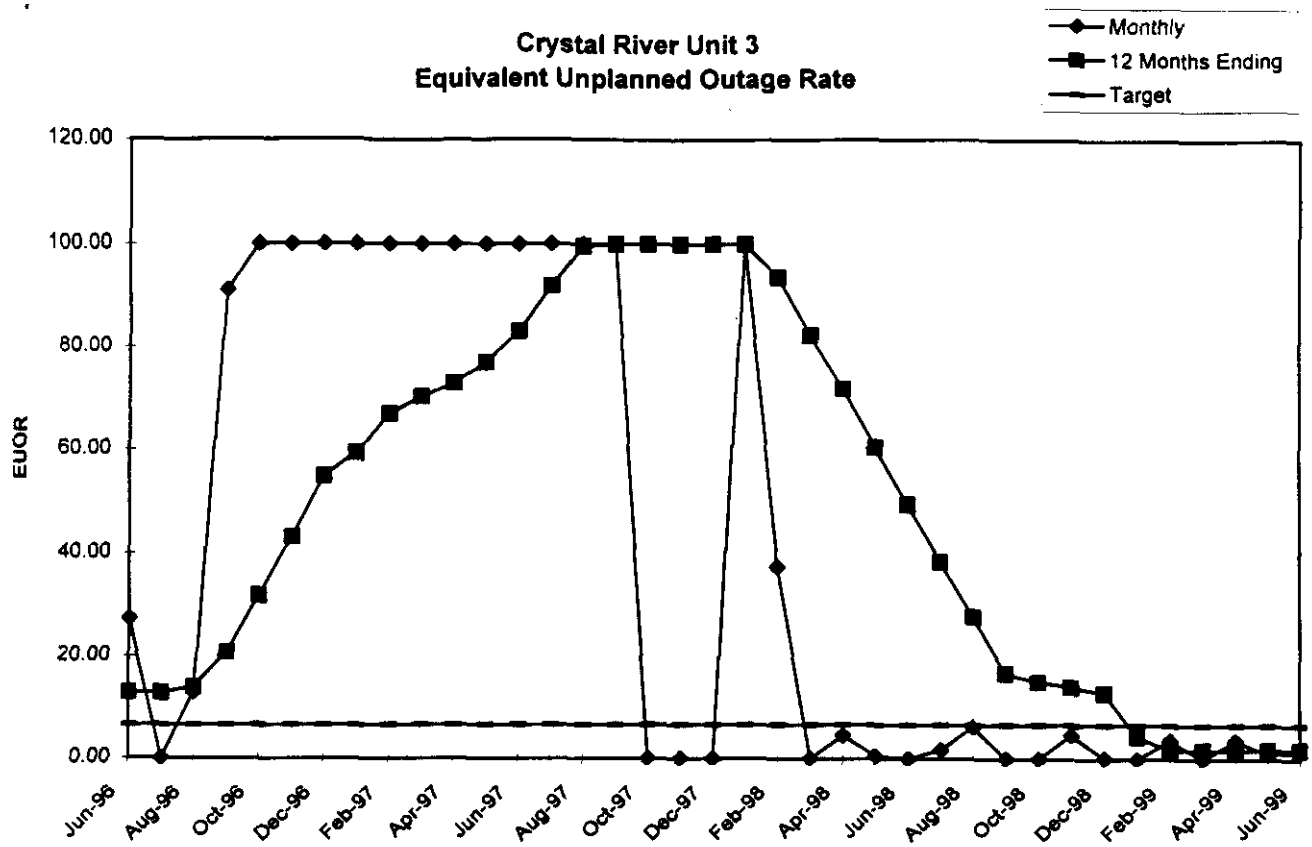
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	100.00	92.56	81.18	70.32	58.91	47.88	36.47	25.67	14.64	13.14	11.95	10.94	2.42	0.45	0.45	0.45	0.45	0.45
MOR	#DIV/0!	2.82	1.13	1.36	0.99	0.78	0.64	0.55	0.48	0.42	0.38	0.34	0.31	0.15	0.15	0.00	0.00	0.00
PFOR	#DIV/0!	3.78	1.50	0.95	0.82	0.65	0.58	0.50	0.43	0.38	0.82	0.74	0.68	0.60	0.60	0.89	0.84	0.94
PMOR	#DIV/0!	9.66	3.82	3.44	2.49	1.96	1.87	1.73	1.51	1.33	1.20	1.09	1.00	0.57	0.57	0.35	0.44	0.46
EUOR	100.00	93.57	82.22	71.74	60.43	49.44	38.28	27.63	16.64	14.94	14.02	12.84	4.34	1.76	1.76	1.68	1.73	1.84
EUOF	74.78	69.98	61.48	53.65	45.19	36.98	28.63	20.66	12.44	12.44	12.83	12.84	4.34	1.76	1.76	1.68	1.73	1.84
POF	25.22	25.22	25.22	25.22	25.22	25.22	25.22	25.22	25.22	16.71	8.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	0.00	4.81	13.30	21.14	29.59	37.81	46.15	54.12	62.34	70.84	78.68	87.16	95.66	98.24	98.24	98.32	98.27	98.16

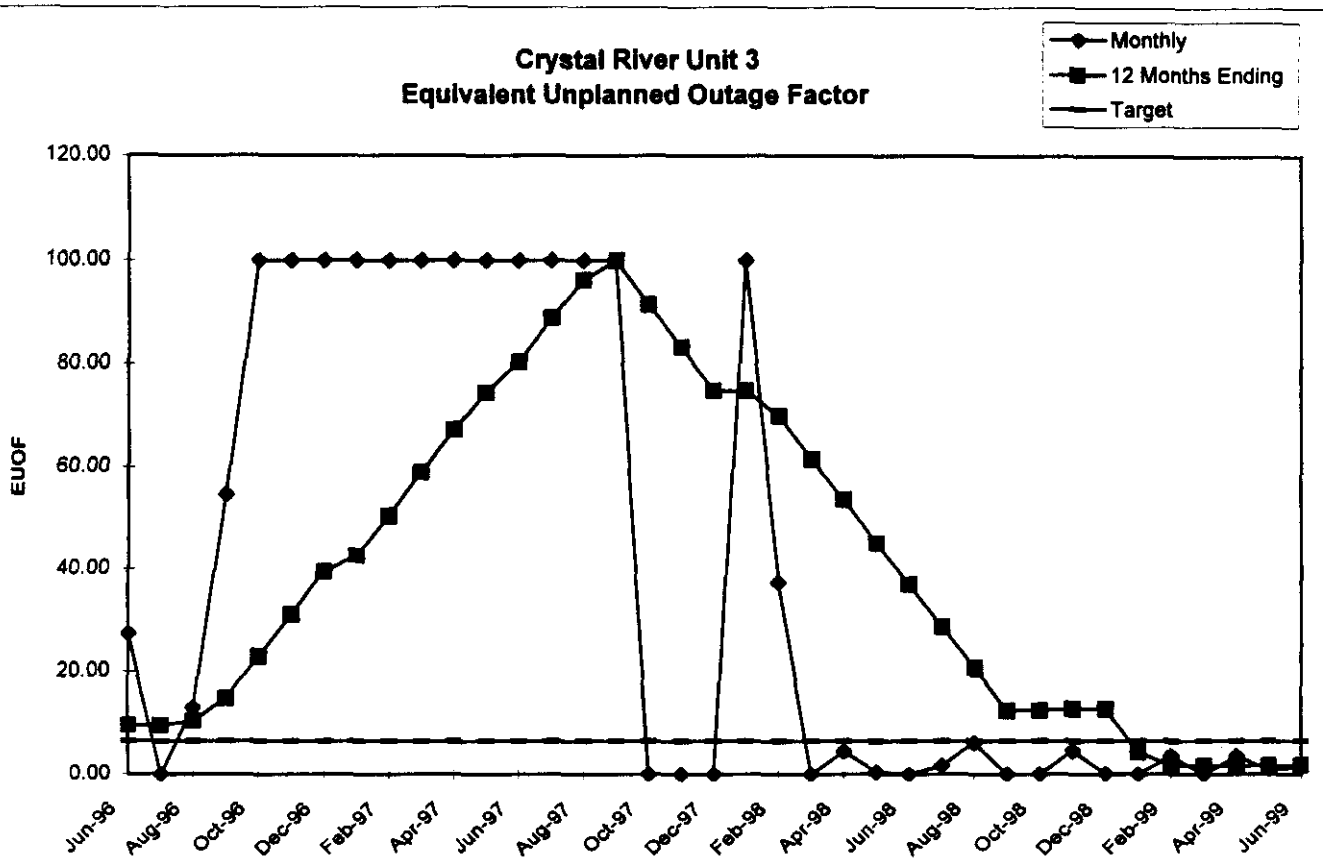

Crystal River Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Crystal River
UNIT 4

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	683.6	684.2	733.4	720	719.1	720	709.9	697.3	27.1	743.3	719	733.6	720	744	730.9	720	682	611.3	663
RSH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UH	36.4	59.8	10.6	0	26	0	34.2	46.7	644.9	0.7	0	10.4	0	0	13.1	0	63	108.7	81
POH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FOH	0	0	10.6	0	26	0	0	46.7	644.9	0.7	0	10.4	0	0	13.1	0	0.9	0	81
MOH	36.4	59.8	0	0	0	0	34.2	0	0	0	0	0	0	0	0	0	62.1	108.7	0
PFOH	537.7	443.8	1.2	3.7	17.7	9.6	52.8	10.1	0	13.4	29.3	0	125.6	19.2	168.1	18.6	5.2	123.4	174.8
LRPF	253.7	184.3	76.4	429.7	47.6	361.2	25.4	334	0	47.7	82.8	0	67.6	47.8	45.8	275.8	47.8	116.6	226.5
EFOH	195.7	117.3	0.1	2.3	1.2	5	1.9	4.8	0	0.9	3.5	0	12.2	1.3	11	7.4	0.4	21	56.8
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	0.00	0.00	1.42	0.00	3.49	0.00	0.00	6.28	95.97	0.09	0.00	1.40	0.00	0.00	1.76	0.00	0.13	0.00	10.89
MOR	5.06	8.04	0.00	0.00	0.00	0.00	4.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.35	15.10	0.00
PFOR	28.63	17.14	0.01	0.32	0.17	0.69	0.27	0.69	0.00	0.12	0.49	0.00	1.69	0.17	1.50	1.03	0.06	3.44	8.57
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	32.24	23.80	1.44	0.32	3.65	0.69	4.85	6.92	95.97	0.22	0.49	1.40	1.69	0.17	3.24	1.03	8.51	18.01	18.52
EUOF	32.24	23.80	1.44	0.32	3.65	0.69	4.85	6.92	95.97	0.22	0.49	1.40	1.69	0.17	3.24	1.03	8.51	18.01	18.52
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	67.76	76.20	98.56	99.68	96.35	99.31	95.15	93.08	4.03	99.78	99.51	98.60	98.31	99.83	96.76	98.97	91.49	81.99	81.48

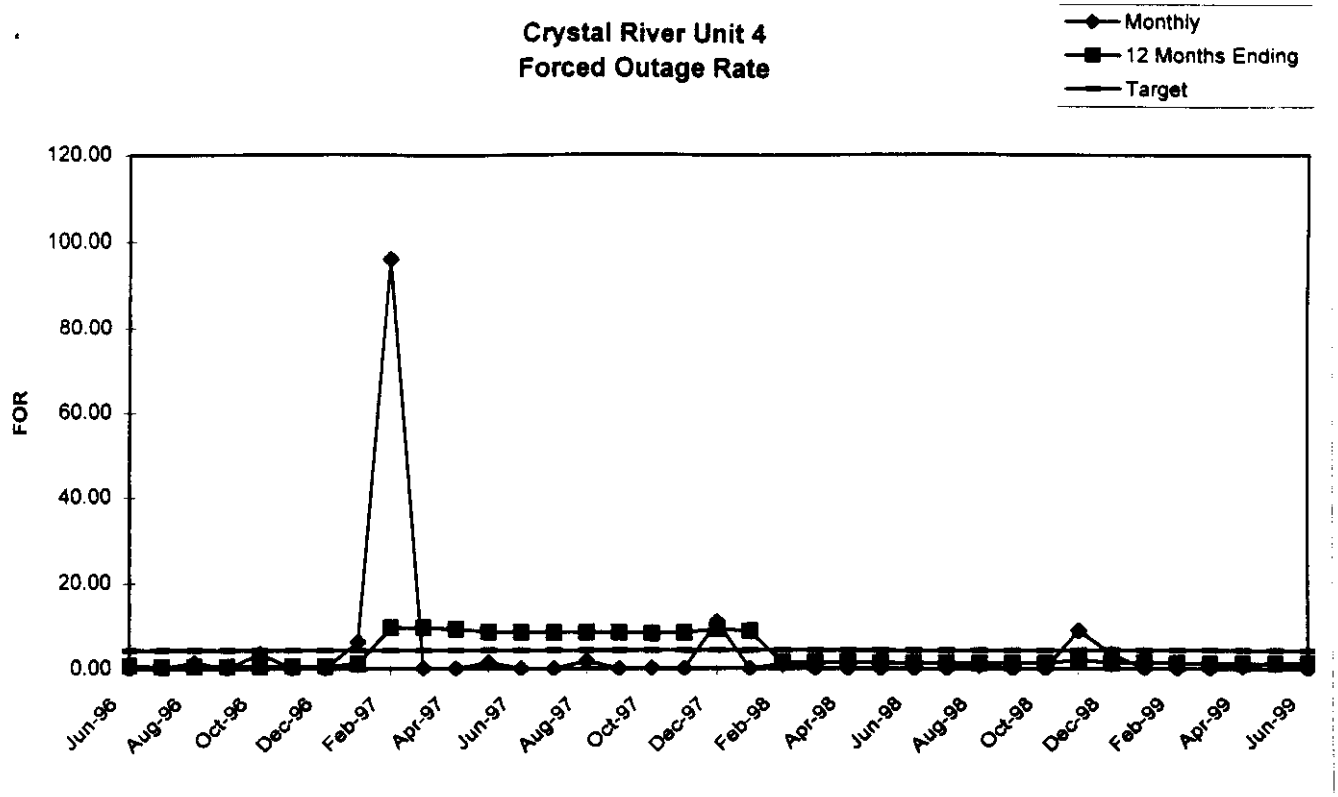
12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	0.72	0.35	0.48	0.48	0.54	0.54	0.55	1.16	9.58	9.55	9.23	8.57	8.53	8.47	8.50	8.50	8.27	8.38	9.29
MOR	0.47	1.24	1.24	1.24	1.24	1.24	1.68	1.69	1.85	1.85	1.79	1.63	1.17	0.43	0.43	0.43	1.20	2.55	2.15
PFOR	4.79	6.15	5.96	5.97	5.88	5.70	5.66	5.73	6.18	5.36	4.64	4.22	1.88	0.42	0.55	0.62	0.61	0.82	1.53
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	5.92	7.63	7.57	7.58	7.55	7.37	7.74	8.38	16.59	15.83	14.85	13.73	11.22	9.21	9.36	9.42	9.83	11.26	12.42
EUOF	5.25	6.77	6.72	6.72	6.70	6.54	6.87	7.43	14.71	14.03	13.61	13.73	11.22	9.21	9.36	9.42	9.83	11.26	12.42
POF	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.32	11.35	11.35	8.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	83.43	81.91	81.96	81.95	81.98	82.14	81.81	81.25	73.94	74.61	78.02	86.27	88.78	90.79	90.64	90.58	90.17	88.74	87.58

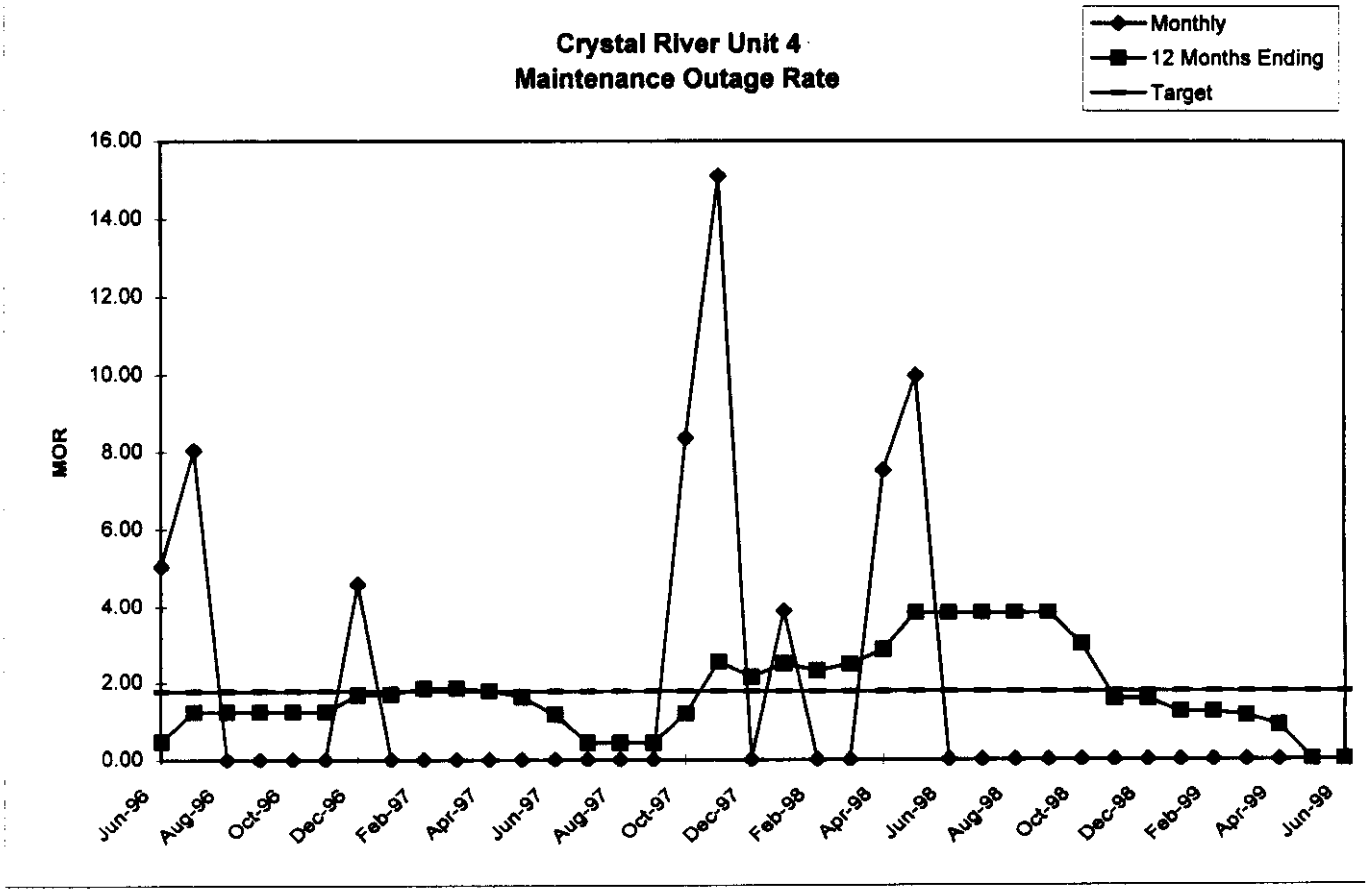
Crystal River
UNIT 4

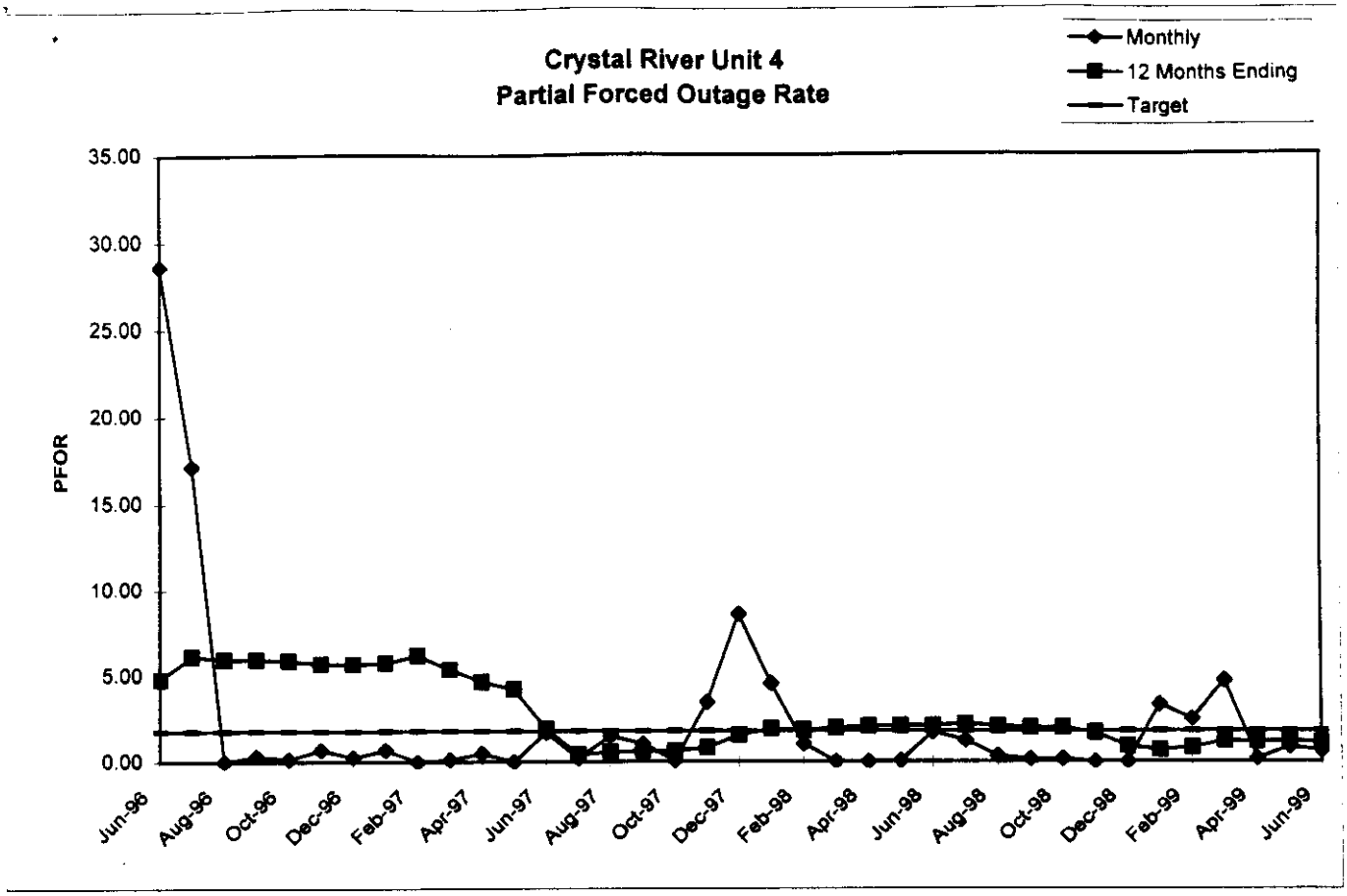
	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744	672	744	719	744	720
SER HOURS	715	665.2	147	196.7	669.8	720.0	744	737.7	720	745	656.1	719.3	462.85	668.33	744	715.28	733.58	720
RSH	0	0	0	0	0	0	0	0	0	0	0	0	281.15	3.67	0	0	0	0
UH	29	6.8	597	522.3	74.2	0.0	0	6.3	0	0	63.9	24.8	0	0	0	3.72	10.42	0
POH	0	0	597	506.3	0.0	0.0	0	0	0	0	0	0	0	0	0	0	0	0
FOH	0	6.8	0	0	0	0	0	6.3	0	0	63.9	24.8	0	0	0	3.72	10.42	0
MOH	29	0	0	16.0	74.2	0.0	0	0	0	0	0	0	0	0	0	0	0	0
PFOH	87.4	13.2	0	0.0	0.4	50.7	26.8	16.7	21.6	7.6	0	0	24.92	20.52	66.17	18.03	12.3	5.92
LRPF	258.6	353.3	0	0.0	697.0	168.8	238.7	100.1	34.8	111.2	0	0	426.775	553.694	367.092	47.7424	355.867	515.333
EFOH	32.4	6.7	0	0.00	0.35	12.27	9.18	2.40	1.08	1.21	0.00	0.00	15.26	16.30	34.85	1.24	6.28	4.38
PMOH	0	0	0	0	0	0	0	0	0	160.20	241.60	0.00	0	0	0	0	85.98	0
LRPM	0	0	0	0	0	0	0	0	0	47.7	680	0	0	0	0	0	47.7475	0
EMOH	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	10.96	235.71	0.00	0.00	0.00	0.00	0.00	5.89	0.00
NPC	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697

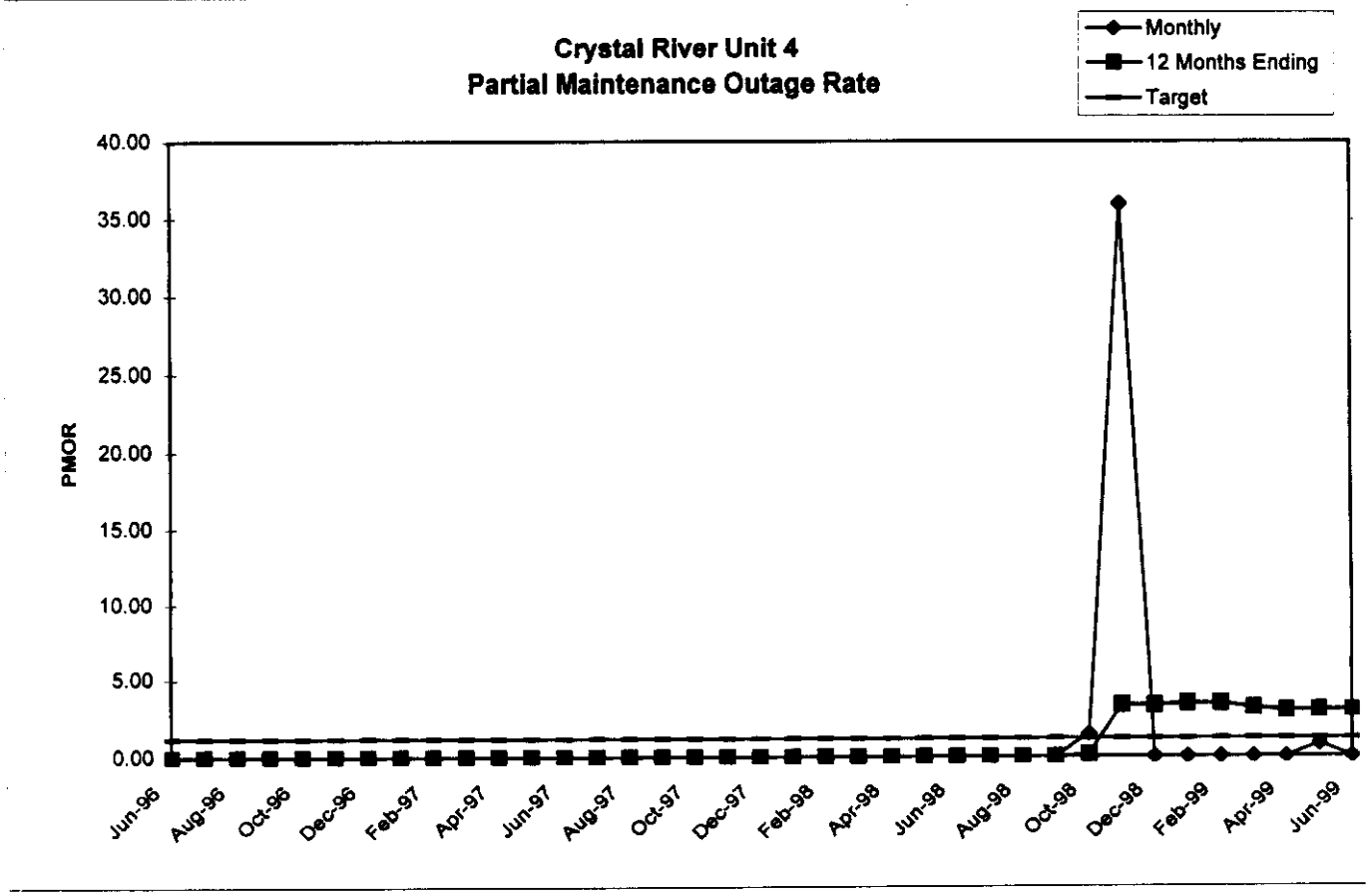
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.00	1.01	0.00	0.00	0.00	0.00	0.00	0.85	0.00	0.00	8.88	3.33	0.00	0.00	0.00	0.52	1.40	0.00
MOR	3.90	0.00	0.00	7.51	9.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	4.53	1.01	0.00	0.00	0.05	1.70	1.23	0.33	0.15	0.16	0.00	0.00	3.30	2.44	4.68	0.17	0.86	0.61
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.47	35.93	0.00	0.00	0.00	0.00	0.00	0.80	0.00
EUOR	8.25	2.01	0.00	7.51	10.02	1.70	1.23	1.17	0.15	1.63	41.61	3.33	3.30	2.44	4.68	0.69	3.04	0.61
EUOF	8.25	2.01	0.00	2.22	10.02	1.70	1.23	1.17	0.15	1.63	41.61	3.33	2.05	2.43	4.68	0.69	3.04	0.61
POF	0.00	0.00	80.24	70.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	91.75	97.99	19.76	27.36	89.98	98.30	98.77	98.83	99.85	98.37	58.39	96.67	97.95	97.57	95.32	99.31	96.96	99.39

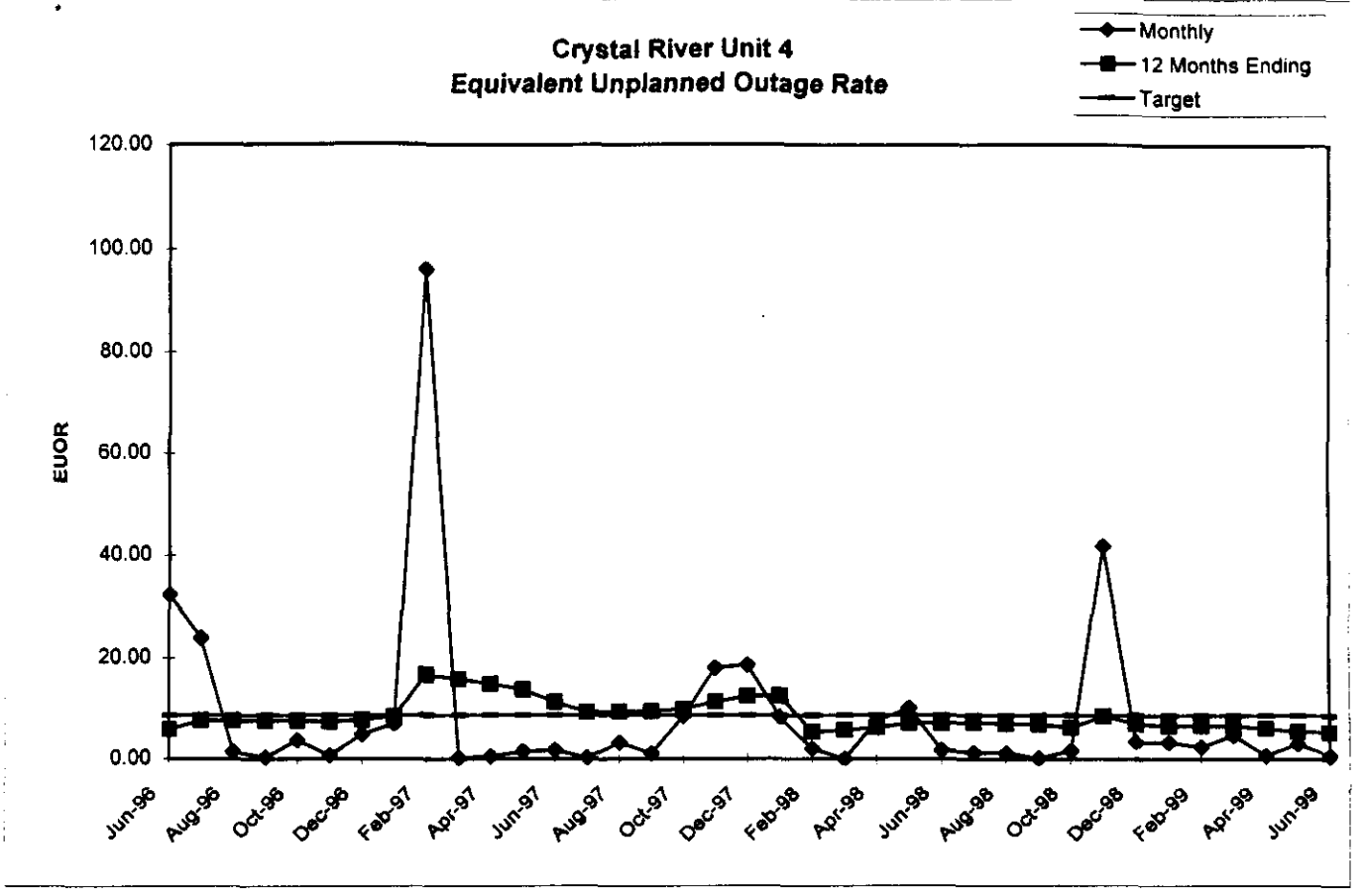
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	8.77	1.32	1.41	1.51	1.38	1.38	1.38	1.29	1.29	1.27	2.10	1.35	1.40	1.30	1.21	1.18	1.29	1.29
MOR	2.49	2.31	2.48	2.86	3.84	3.84	3.84	3.83	3.83	3.01	1.59	1.58	1.24	1.24	1.15	0.89	0.00	0.00
PFOR	1.88	1.82	1.94	2.04	2.06	2.06	2.17	2.05	1.96	1.95	1.66	0.88	0.67	0.81	1.19	1.13	1.20	1.10
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	3.34	3.32	3.43	3.43	3.17	2.97	3.02	3.02
EUOR	12.53	5.32	5.69	6.23	7.07	7.07	7.17	6.97	6.89	6.22	8.44	6.96	6.60	6.65	6.58	6.06	5.45	5.36
EUOF	12.53	5.32	5.30	5.45	6.18	6.18	6.27	6.09	6.02	5.44	7.38	6.09	5.56	5.59	5.99	5.86	5.27	5.18
POF	0.00	0.00	6.82	12.59	12.59	12.59	12.59	12.59	12.59	12.59	12.59	12.59	12.59	12.59	5.78	0.00	0.00	0.00
EAF	87.47	94.68	87.88	81.96	81.23	81.22	81.13	81.31	81.38	81.97	80.03	81.32	81.84	81.81	88.23	94.14	94.73	94.82

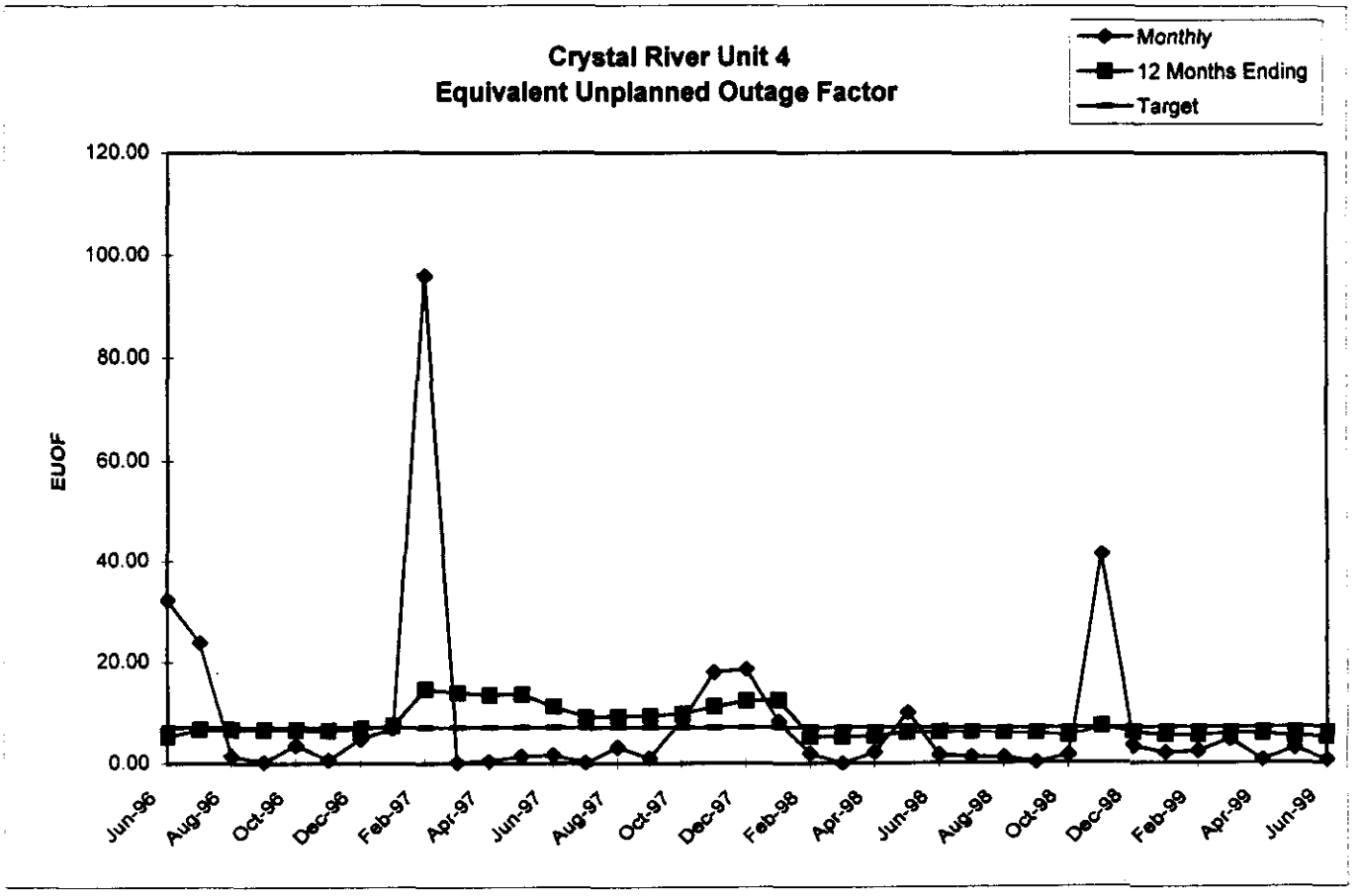

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Crystal River
UNIT 5

	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
PER HOURS	720	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720	744
SER HOURS	600.8	739.7	738.7	719.2	738.7	720	744	744	650.5	674.5	1.3	737.2	720	744	744	712	745	720	744
RSH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UH	119.2	4.3	5.3	0.8	6.3	0	0	0	21.5	69.5	717.7	6.9	0	0	0	8	0	0	0
POH	0	0	57.4	0	0	0	0	0	0	69.5	717.7	0	0	0	0	0	0	0	0
FOH	119.2	4.3	5.3	0.8	6.3	0	0	0	21.5	0	0	6.9	0	0	0	8	0	0	0
MOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PFOH	75.8	16.7	52.1	23.8	91.3	18.3	52.8	35	51.2	19	0	28.1	31	20.2	45.2	4.8	22.5	23	201
LRPF	146.3	244.7	178.9	285.7	87	278	213.2	439.8	104.9	196.3	0	246.8	47.7	95.1	47.7	440.9	271.9	183.5	33.4
EFOH	15.9	5.9	13.4	9.8	11.4	7.3	16.2	22.1	7.7	5.3	0	9.9	2.1	2.8	3.1	3	8.8	6.1	9.6
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697

MONTHLY	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	16.56	0.58	0.71	0.11	0.85	0.00	0.00	0.00	3.20	0.00	0.00	0.93	0.00	0.00	0.00	1.11	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	2.65	0.80	1.81	1.36	1.54	1.01	2.18	2.97	1.18	0.79	0.00	1.34	0.29	0.38	0.42	0.42	1.18	0.85	1.29
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	18.76	1.37	2.51	1.47	2.38	1.01	2.18	2.97	4.35	0.79	0.00	2.26	0.29	0.38	0.42	1.53	1.18	0.85	1.29
EUOF	18.76	1.37	2.51	1.47	2.38	1.01	2.18	2.97	4.35	0.71	0.00	2.26	0.29	0.38	0.42	1.53	1.18	0.85	1.29
POF	0.00	0.00	7.72	0.00	0.00	0.00	0.00	0.00	0.00	9.34	99.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	81.24	98.63	89.77	98.53	97.62	98.99	97.82	97.03	95.65	89.95	0.18	97.74	99.71	99.62	99.58	98.47	98.82	99.15	98.71

12 MONTHS	Jun-96	Jul-96	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	May-97	Jun-97	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97
FOR	2.54	2.59	1.87	1.88	1.95	1.95	1.95	1.95	2.11	1.81	1.97	2.06	0.57	0.51	0.45	0.54	0.46	0.46	0.46
MOR	0.49	0.49	0.49	0.49	0.49	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.45	1.45	1.46	1.56	1.55	1.43	1.44	1.63	1.64	1.64	1.65	1.60	1.40	1.36	1.23	1.15	1.11	1.10	1.01
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	4.40	4.46	3.77	3.88	3.93	3.81	3.36	3.54	3.72	3.42	3.59	3.63	1.96	1.87	1.67	1.68	1.56	1.55	1.47
EUOF	4.40	4.46	3.77	3.88	3.93	3.81	3.36	3.54	3.72	3.40	3.27	3.30	1.78	1.70	1.52	1.53	1.42	1.41	1.33
POF	0.00	0.00	0.65	0.65	0.65	0.65	0.65	0.65	0.66	1.45	9.64	9.64	9.64	9.64	8.99	8.99	8.99	8.99	8.99
EAF	95.60	95.54	95.58	95.47	95.41	95.53	95.98	95.80	95.63	95.15	87.09	87.06	88.58	88.66	89.49	89.49	89.59	89.60	89.68

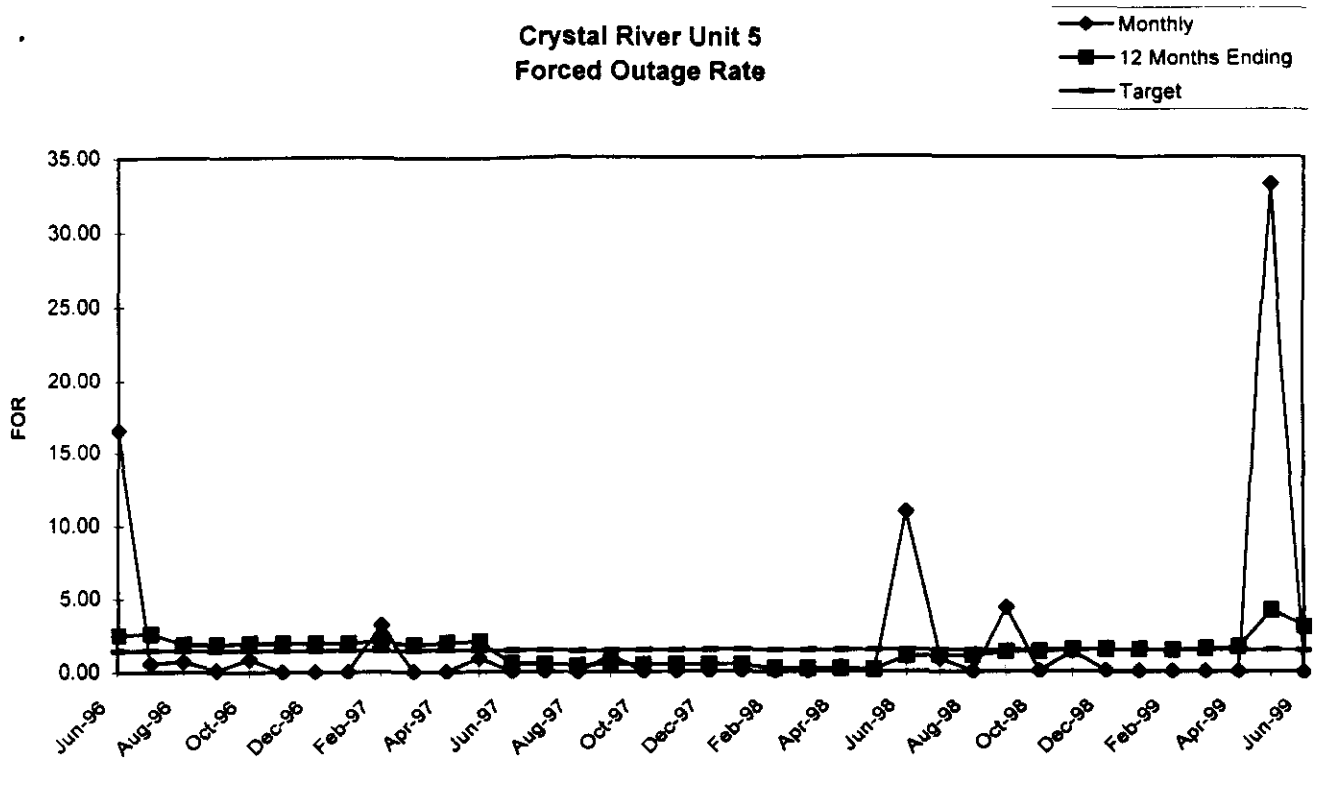
Crystal River
UNIT 5

	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
PER HOURS	744	672	744	719	744	720	744	744	720	745	720	744	744	672	744	719	744	720
SER HOURS	744	607.5	744	705.6	744.0	641.3	737.7	744	688.8	745	710.3	676.1	744	672	277.38	0.02	356.83	711.68
RSH	0	64.5	0	11.5	0.0	0.0	0	0	0	0	0	0	0	0	9.63	0	0	0
UH	0	0	0	1.9	0.0	78.7	6.3	0	31.2	0	9.7	67.9	0	0	456.98	718.98	387.17	8.32
POH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	456.98	718.98	209.83	0
FOH	0	0	0	1.9	0.0	78.7	6.3	0	31.2	0	9.7	0	0	0	0	0	177.33	0
MOH	0	0	0	0	0	0	0	0	0	0	0	67.9	0	0	0	0	0	8.32
PFOH	65.8	9.7	0	45.2	2.2	56.3	32.5	12.6	17.2	10.3	89.9	0	72.25	8.6	38.5	0	4.65	0
LRPF	188.6	506	0	449.1	124.0	55.2	284.2	467.5	100	365.9	697	0	28.8119	481.335	85.9392	0	47.6658	0
EFOH	17.8	7	0	29.13	0.40	4.46	13.25	8.45	2.47	5.41	89.90	0.00	2.99	5.94	4.75	0.00	0.32	0.00
PMOH	4.8	0	29	0.0	122.3	0.0	0	0	0	0	168.2	113.2	69.03	0	0	0	0	0
LRPM	47.7	0	238.7	0.0	47.7	0.0	0	0	0	0	697	47.7	16.2348	0	0	0	0	0
EMOH	0.3	0	9.9	0.00	8.37	0.00	0.00	0.00	0.00	0.00	168.20	7.75	1.61	0.00	0.00	0.00	0.00	0.00
NPC	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697

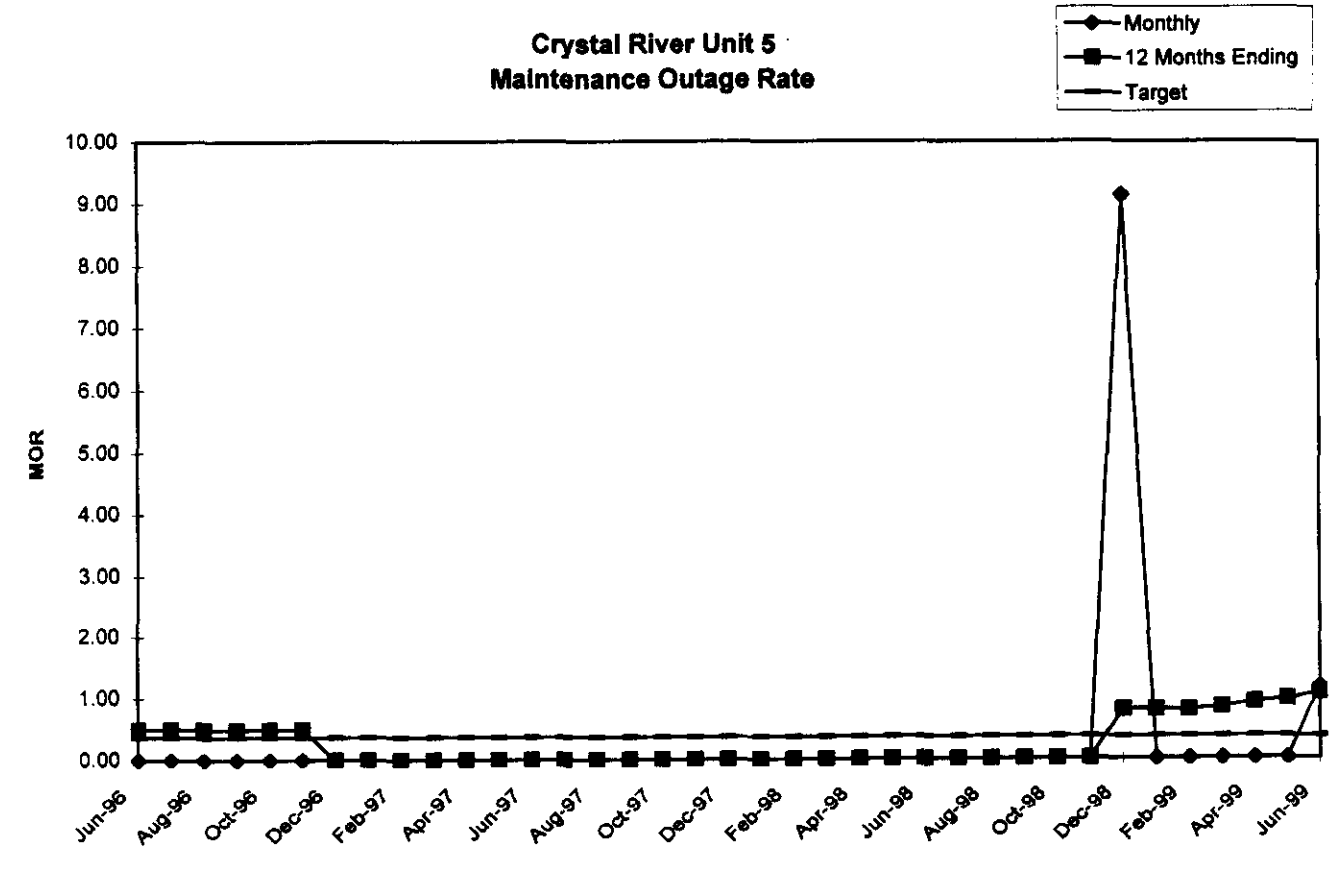
MONTHLY	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.00	0.00	0.00	0.26	0.00	10.93	0.85	0.00	4.33	0.00	1.35	0.00	0.00	0.00	0.00	0.00	33.20	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.13	0.00	0.00	0.00	0.00	0.00	1.16
PFOR	2.39	1.15	0.00	4.13	0.05	0.70	1.80	1.14	0.36	0.73	12.66	0.00	0.40	0.88	1.71	0.00	0.09	0.00
PMOR	0.04	0.00	1.33	0.00	1.13	0.00	0.00	0.00	0.00	0.00	23.68	1.15	0.22	0.00	0.00	0.00	0.00	0.00
EUOR	2.43	1.15	1.33	4.38	1.18	11.55	2.63	1.14	4.68	0.73	37.19	10.17	0.62	0.88	1.71	0.00	33.26	1.16
EUOF	2.43	1.04	1.33	4.31	1.18	11.55	2.63	1.14	4.68	0.73	37.19	10.17	0.62	0.88	0.64	0.00	23.88	1.16
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.42	100.00	28.20	0.00
EAF	97.57	98.96	98.67	95.69	98.82	88.45	97.37	98.86	95.32	99.27	62.81	89.83	99.38	99.12	37.94	0.00	47.92	98.84

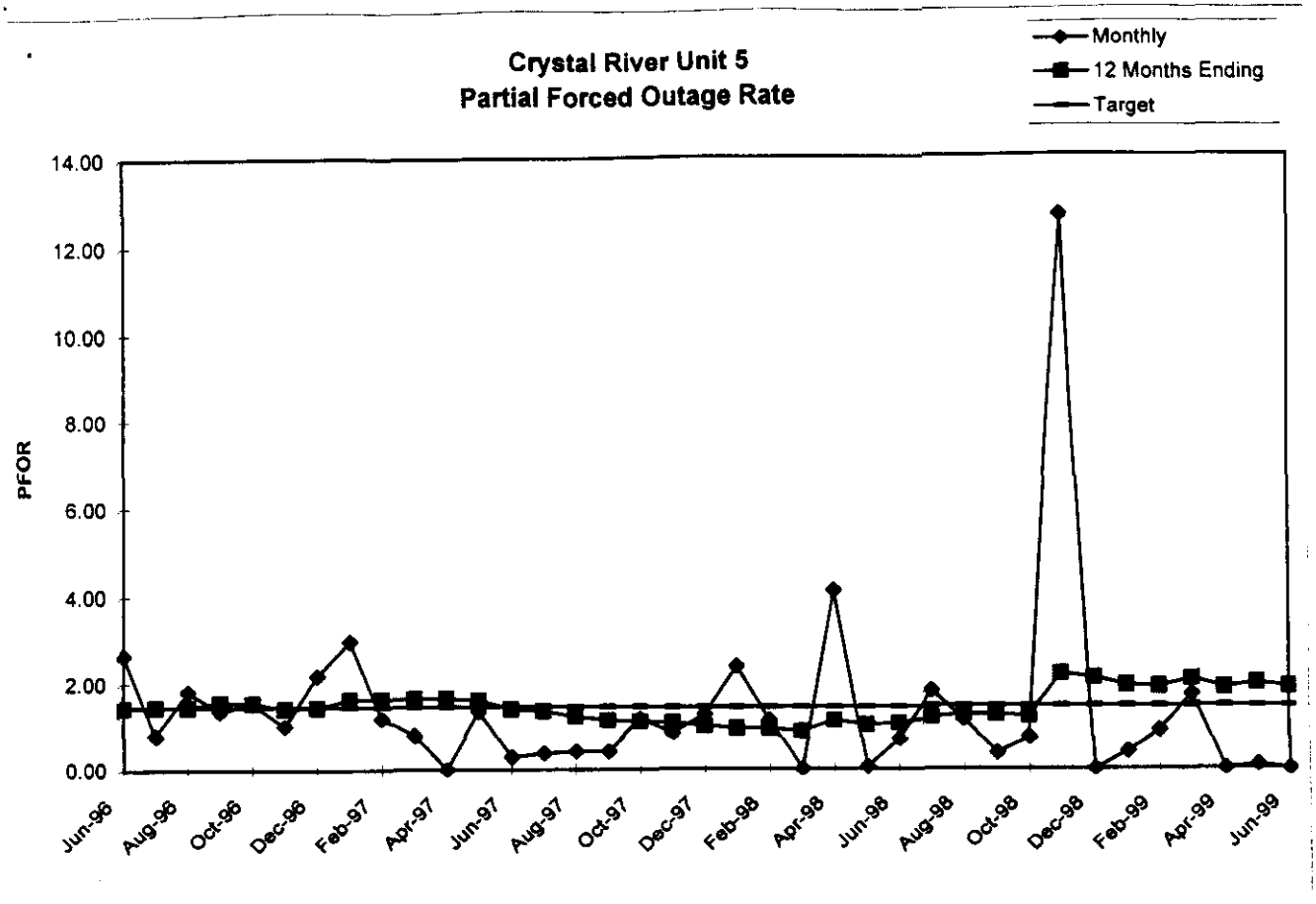
12 MONTHS	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
FOR	0.46	0.19	0.19	0.19	0.11	1.02	1.09	1.09	1.36	1.36	1.47	1.48	1.48	1.47	1.56	1.68	4.16	3.08
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.79	0.79	0.79	0.83	0.91	0.96	1.07
PFOR	0.96	0.96	0.88	1.15	1.04	1.07	1.20	1.26	1.25	1.21	2.20	2.10	1.93	1.90	2.07	1.87	1.97	1.89
PMOR	0.00	0.00	0.13	0.12	0.21	0.22	0.22	0.22	0.22	0.22	2.18	2.29	2.31	2.29	2.30	2.52	2.54	2.51
EUOR	1.42	1.15	1.19	1.45	1.36	2.30	2.49	2.55	2.81	2.77	5.79	6.55	6.39	6.33	6.63	6.84	9.32	8.31
EUOF	1.29	1.04	1.09	1.44	1.35	2.28	2.47	2.53	2.79	2.75	5.74	6.49	6.34	6.32	6.26	5.91	7.84	6.98
POF	8.99	8.99	8.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.22	13.42	15.82	15.82
EAF	89.72	89.98	90.72	98.56	98.65	97.72	97.53	97.47	97.21	97.25	94.26	93.51	93.66	93.68	88.52	80.67	76.34	77.20

Crystal River Unit 5
Forced Outage Rate



Crystal River Unit 5
Maintenance Outage Rate




Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
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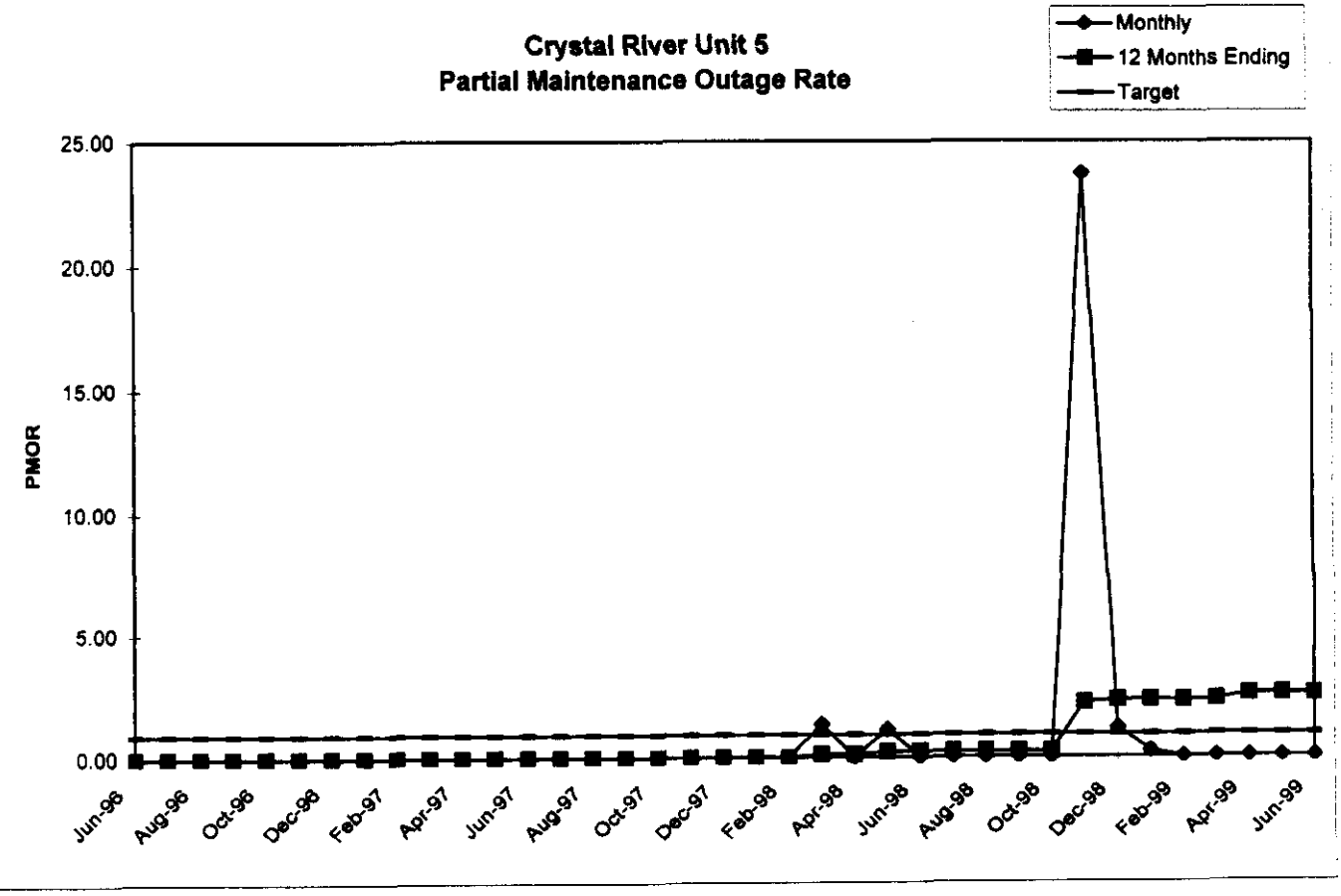
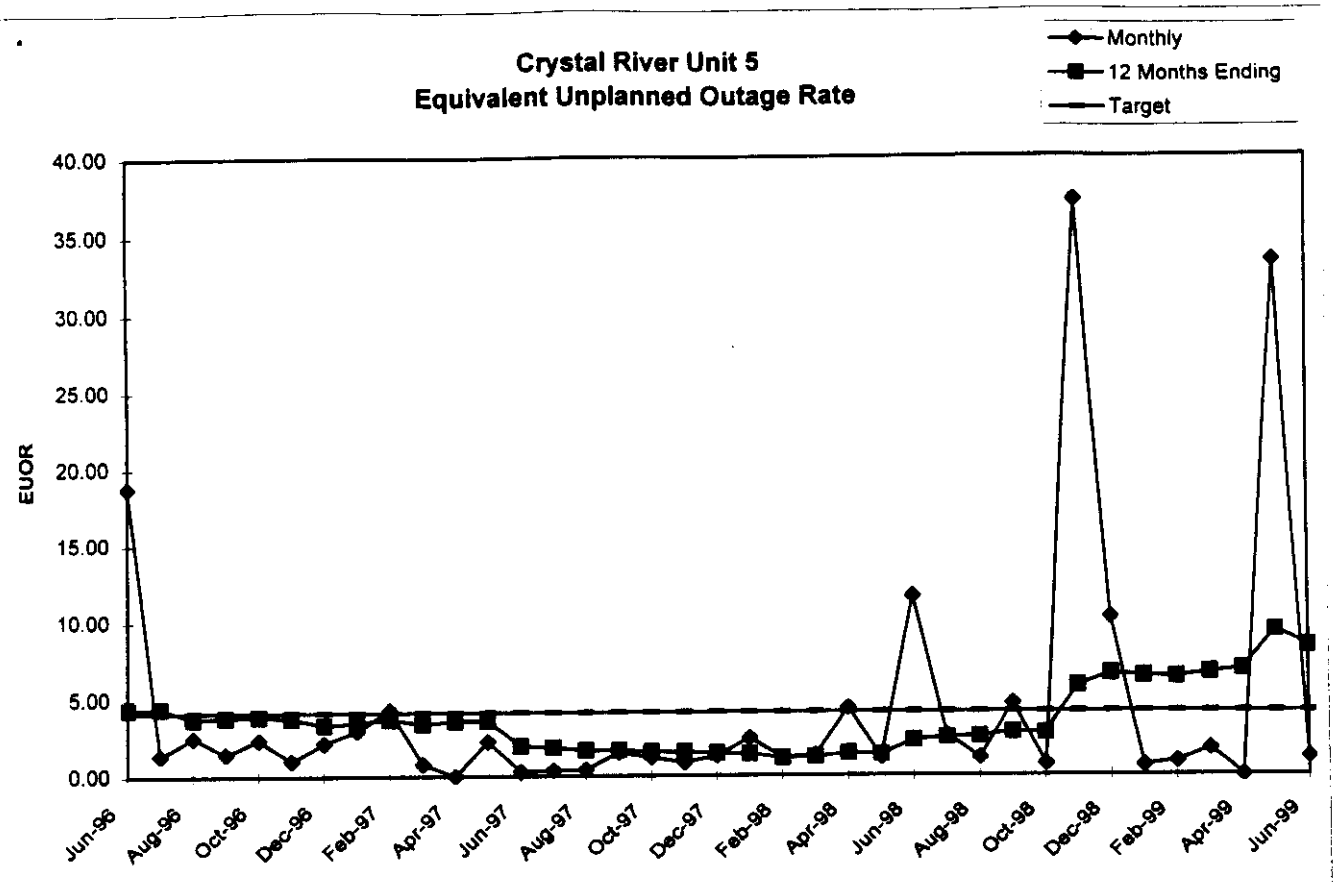
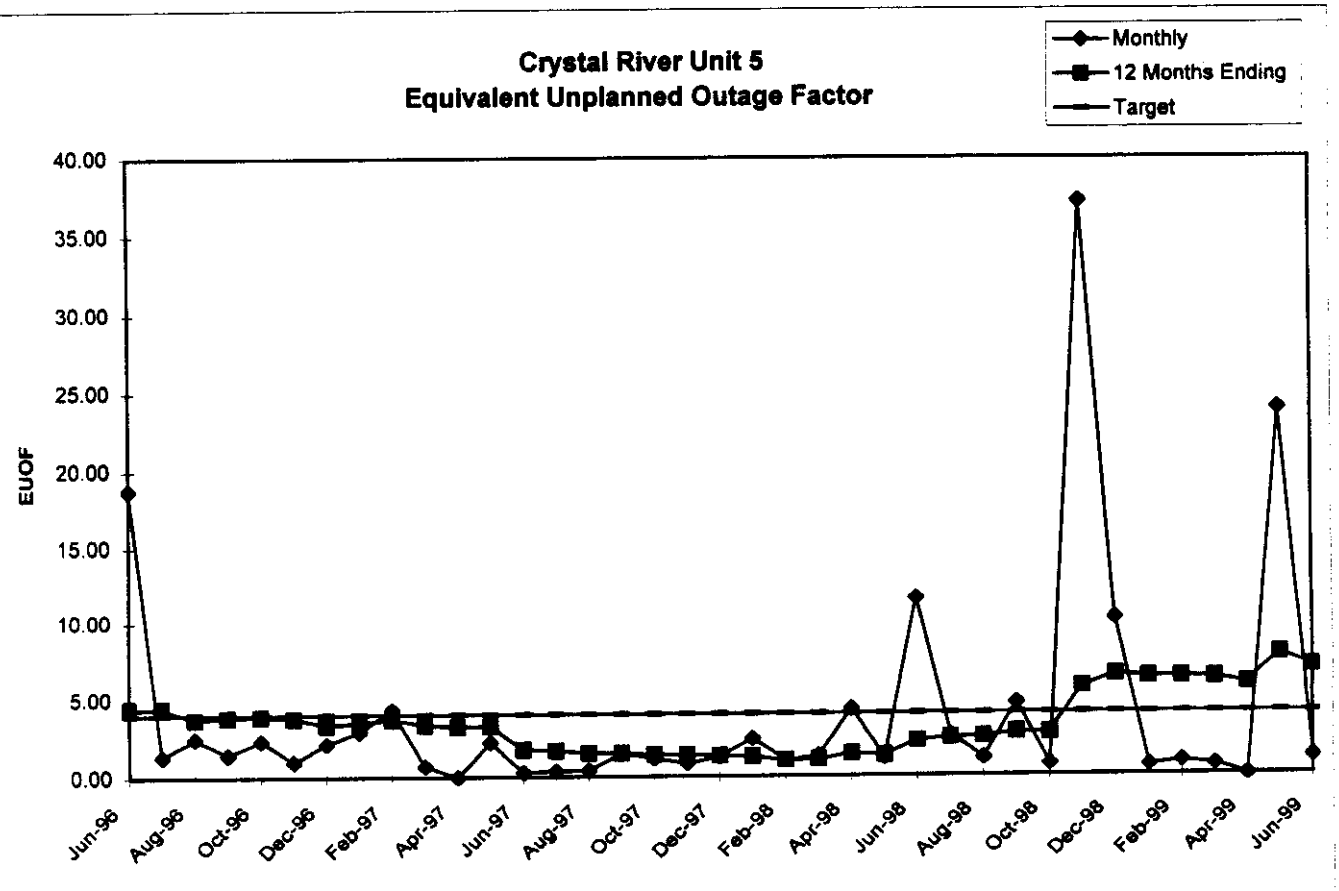
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
25.00
20.00
15.00
10.00
5.00
0.00
Jun-96
Aug-96
Oct-96
Dec-96
Feb-97
Apr-97
Jun-97
Aug-97
Oct-97
Dec-97
Feb-98
Apr-98
Jun-98
Aug-98
Oct-98
Dec-98
Feb-99
Apr-99
Jun-99

Crystal River Unit 5
Equivalent Unplanned Outage Rate



Crystal River Unit 5
Equivalent Unplanned Outage Factor



Tiger Bay

	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98
PER HOURS	744	744	720	745	720	744	744	672	744	719	744	720	744	744	720	745	720
SER HOURS	408.02	736.13	720	736.8	720	744	744	672	586.18	335.0	600.7	720.0	701.1	616.33	686	724.62	205.27
RSH	335.98	0	0	0	0	0	0	0	157.82	0.0	0.0	0.0	0	0	0	0	243.18
UH	0	7.87	0	8.2	0	0	0	0	0	384.0	143.3	0.0	42.88	127.67	34	20.38	271.55
POH	0	0	0	0	0	0	0	0	0	384	14.72	0	0	0	0	0	0
FOH	0	7.87	0	8.2	0	0	0	0	0	0.0	128.6	0.0	42.88	72.53	34	20.38	271.55
MOH	0	0	0	0	0	0	0	0	0	0	0	0	0	55.13	0	0	0
PFOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRPM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206

MONTHLY	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98
FOR	0.00	1.06	0.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	17.63	0.00	5.76	10.53	4.72	2.74	56.95
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.21	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	1.06	0.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	17.63	0.00	5.76	17.16	4.72	2.74	56.95
EUOF	0.00	1.06	0.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	17.28	0.00	5.76	17.16	4.72	2.74	37.72
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.41	1.98	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	98.94	100.00	98.90	100.00	100.00	100.00	100.00	100.00	46.59	80.74	100.00	94.24	82.84	95.28	97.26	62.28

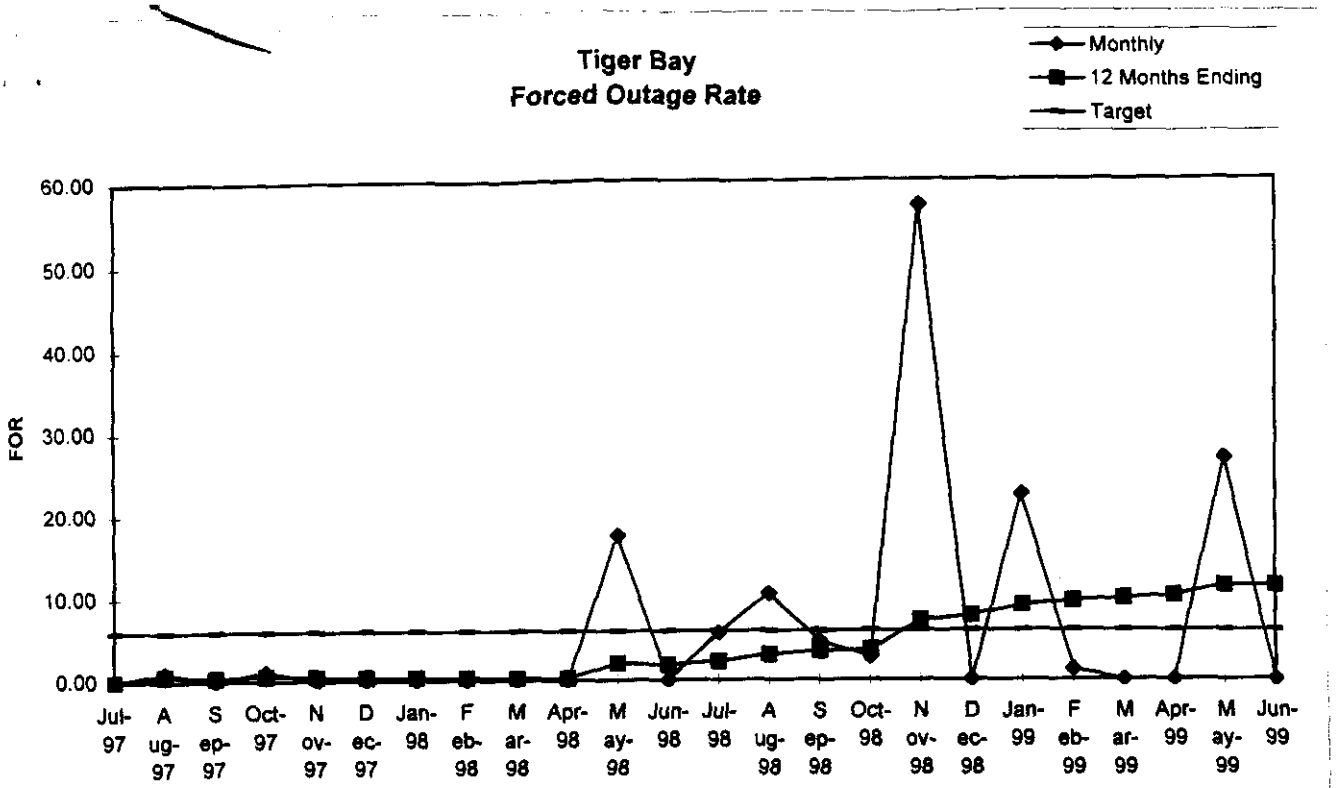
12 MONTHS	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98
FOR	0.00	0.68	0.42	0.61	0.48	0.39	0.33	0.29	0.26	0.25	2.02	1.84	2.29	3.10	3.51	3.66	7.21
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69	0.70	0.70	0.75
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	0.68	0.42	0.61	0.48	0.39	0.33	0.29	0.26	0.25	2.02	1.84	2.29	3.75	4.16	4.31	7.85
EUOF	0.00	0.53	0.36	0.54	0.44	0.36	0.31	0.28	0.24	0.22	1.80	1.65	2.14	3.51	3.90	4.04	7.14
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.26	4.96	4.55	4.55	4.55	4.55	4.55	4.55
EAF	100.00	99.47	99.64	99.46	99.56	99.64	99.69	99.72	99.76	94.52	93.24	93.80	93.31	91.94	91.55	91.41	88.31

Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
744	744	672	744	719	744	720
151.63	132.1	368.8	385.8	123.8	544.5	720
229.48	573.5	298.7	0	0	0	0
362.88	38.37	4.53	358.2	595.2	199.5	0
0	0	0	358.2	526	0	0
0	38.37	4.53	0	0	199.5	0
362.88	0	0	0	69.2	0	0
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0.00	0.00	0.00	0.00	0.00	1.02	1.99
0	0	0	0	0	0	0
0	0	0	0	0	0	0
0.00	0.00	0.00	0.00	7.04	2.53	0.00
206	206	206	206	206	206	206

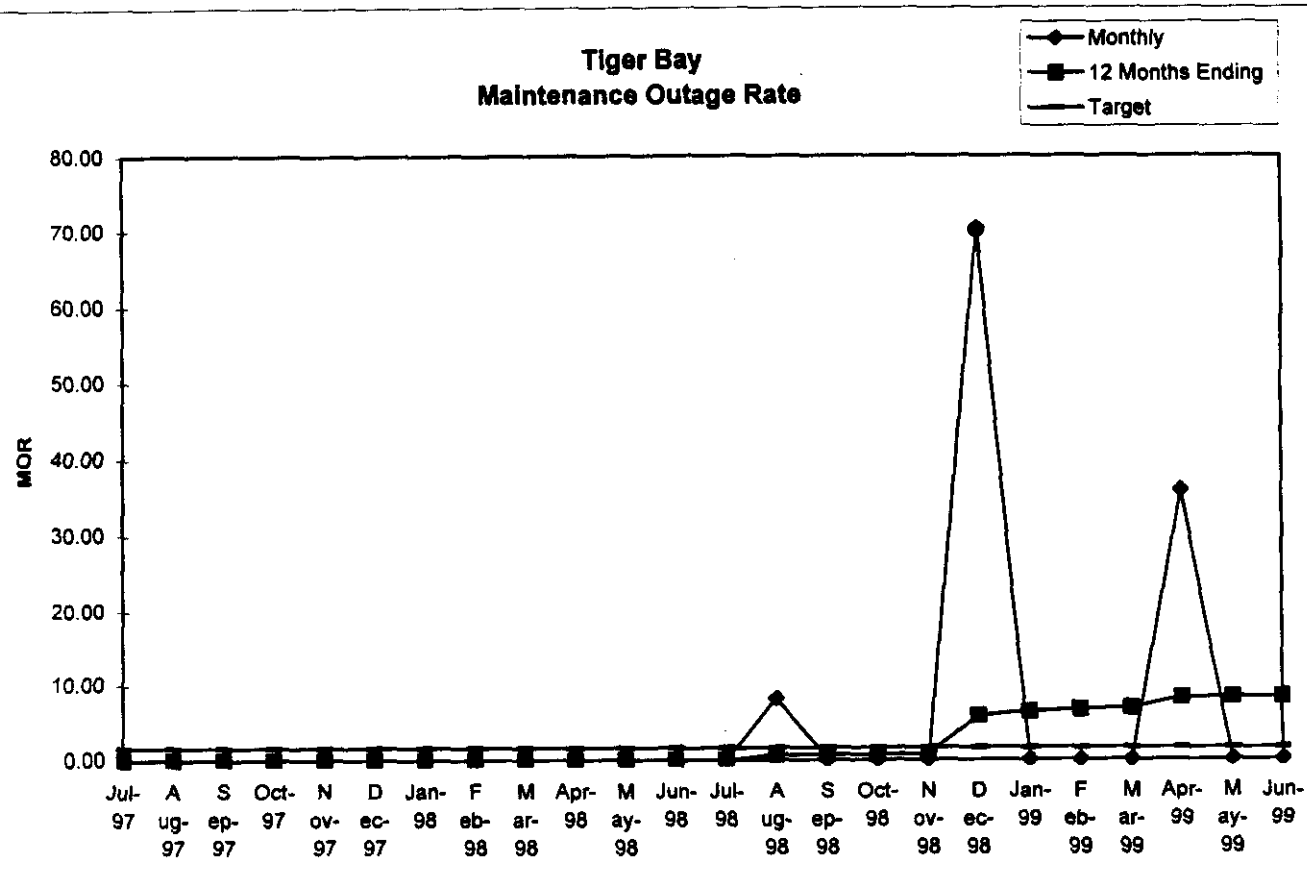
Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
0.00	22.50	1.21	0.00	0.00	26.82	0.00
70.53	0.00	0.00	0.00	35.86	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.19	0.28
0.00	0.00	0.00	0.00	5.69	0.46	0.00
70.53	22.50	1.21	0.00	39.51	27.29	0.28
48.77	5.16	0.67	0.00	10.60	27.29	0.28
0.00	0.00	0.00	48.14	73.16	0.00	0.00
51.23	94.84	99.33	51.86	16.24	72.71	99.72

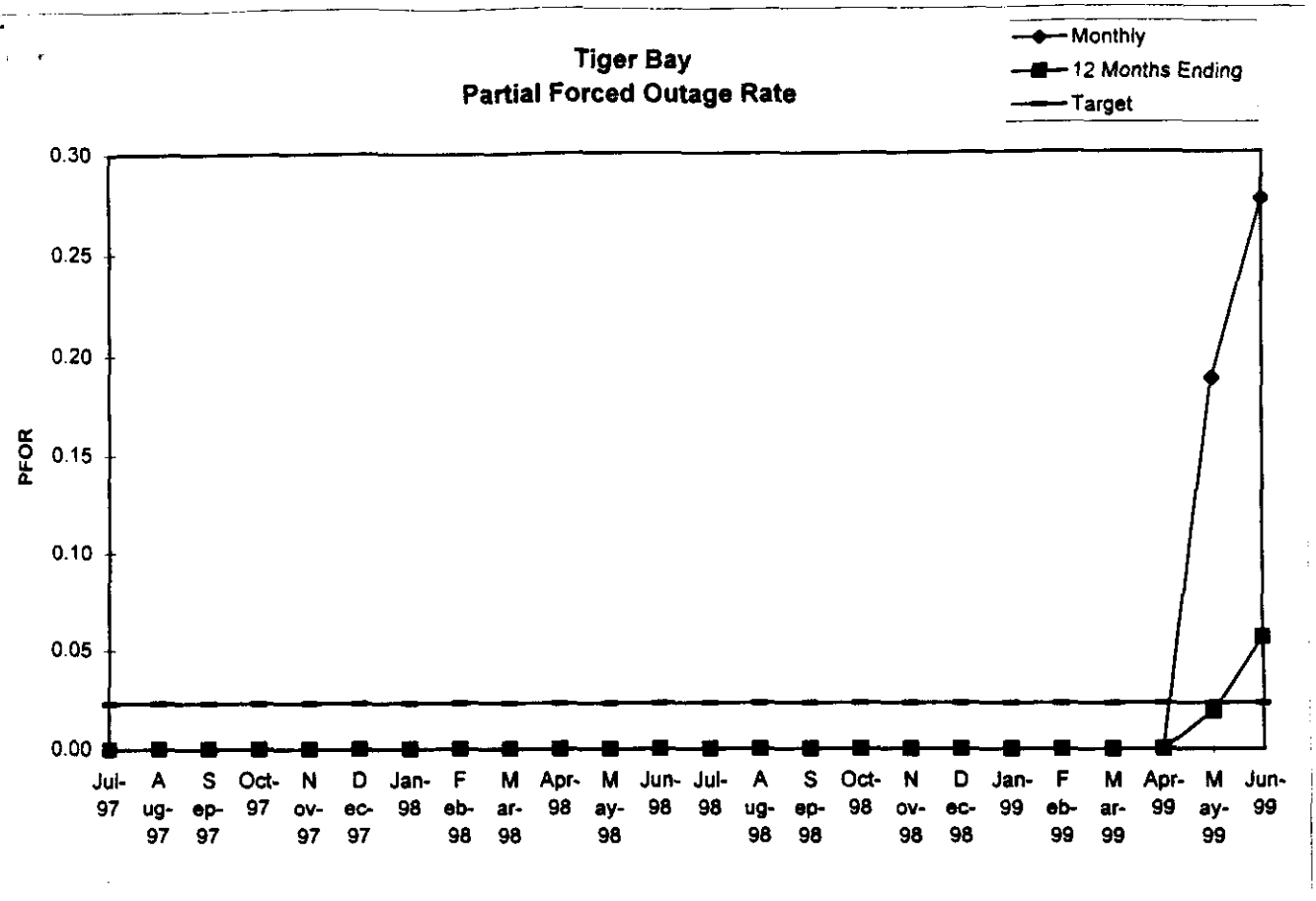
Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99
7.79	9.03	9.52	9.82	10.16	11.31	11.31
5.84	6.38	6.69	6.91	8.25	8.33	8.33
0.00	0.00	0.00	0.00	0.00	0.02	0.06
0.00	0.00	0.00	0.00	0.13	0.18	0.18
12.78	14.34	15.03	15.48	16.99	18.09	18.12
11.28	11.72	11.77	11.77	12.64	13.49	13.51
4.55	4.55	4.55	8.64	10.26	10.09	10.09
84.17	83.73	83.68	79.59	77.10	76.42	76.40

Tiger Bay
Forced Outage Rate



Tiger Bay
Maintenance Outage Rate




Tiger Bay
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Jul-97
Aug-97
Sep-97
Oct-97
Nov-97
Dec-97
Jan-98
Feb-98
Mar-98
Apr-98
May-98
Jun-98
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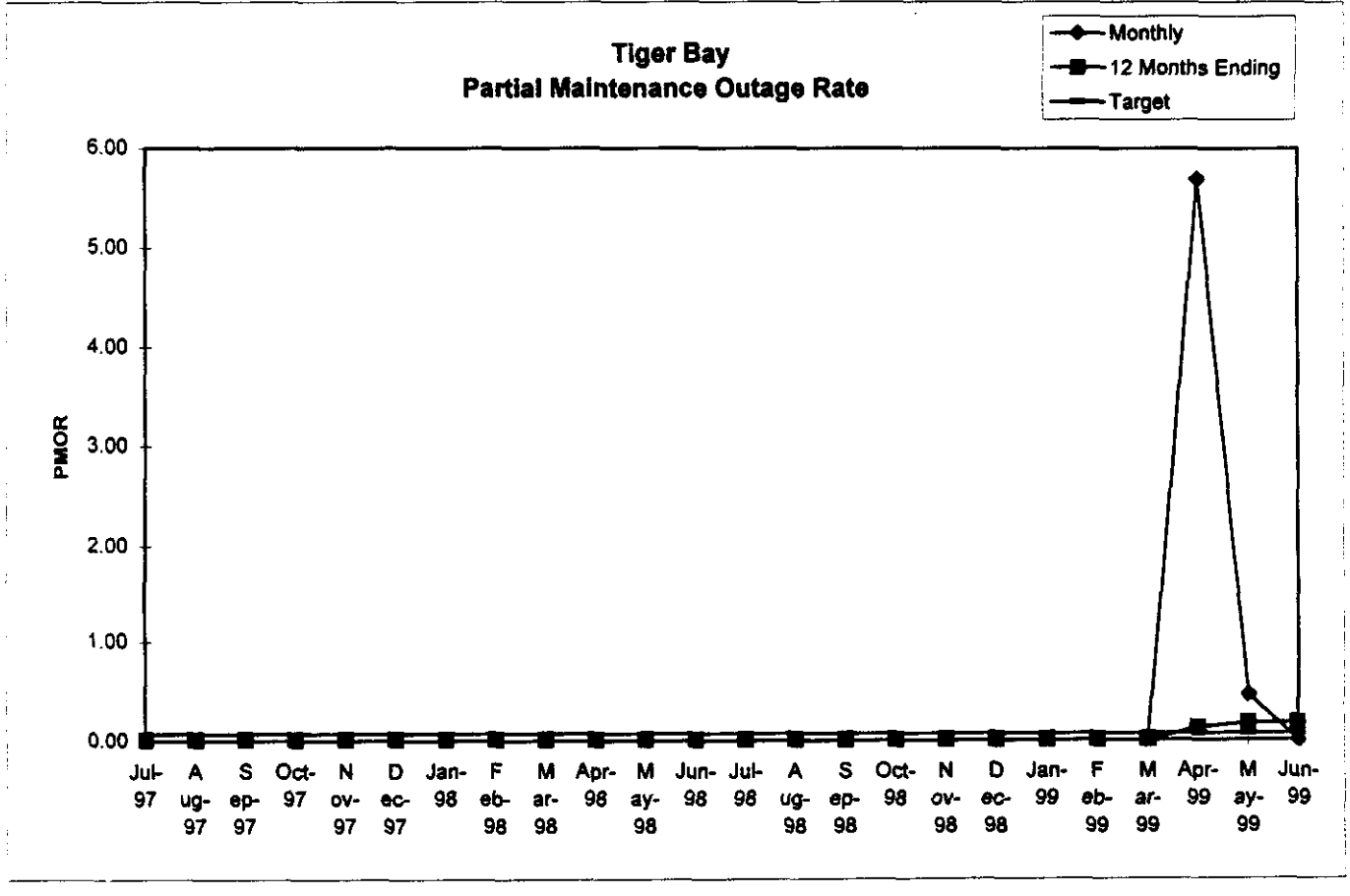
May-99
Jun-99


Tiger Bay
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-97
Aug-97
Sep-97
Oct-97
Nov-97
Dec-97
Jan-98
Feb-98
Mar-98
Apr-98
May-98
Jun-98
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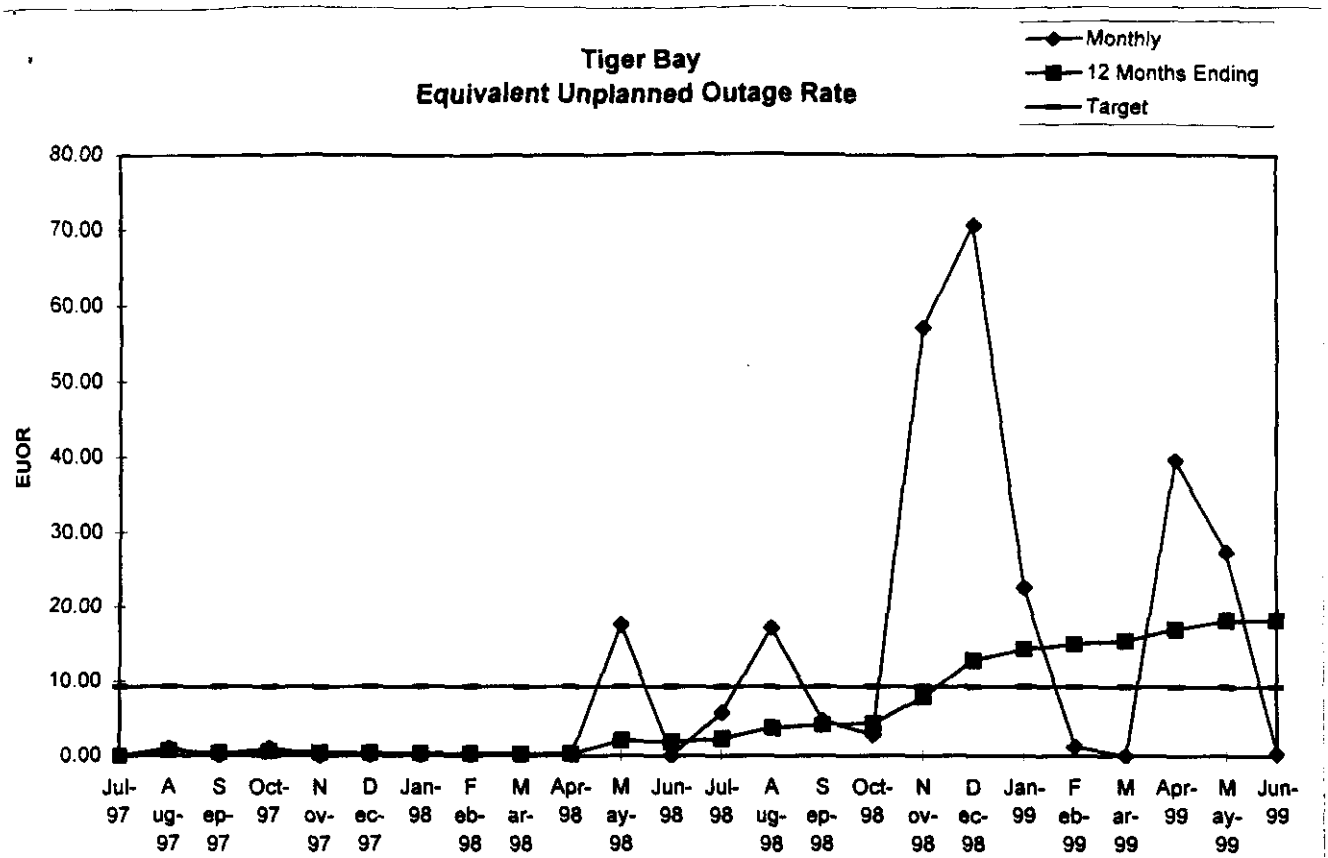
May-99
Jun-99


Tiger Bay
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-97
Aug-97
Sep-97
Oct-97
Nov-97
Dec-97
Jan-98
Feb-98
Mar-98
Apr-98
May-98
Jun-98
Jul-98
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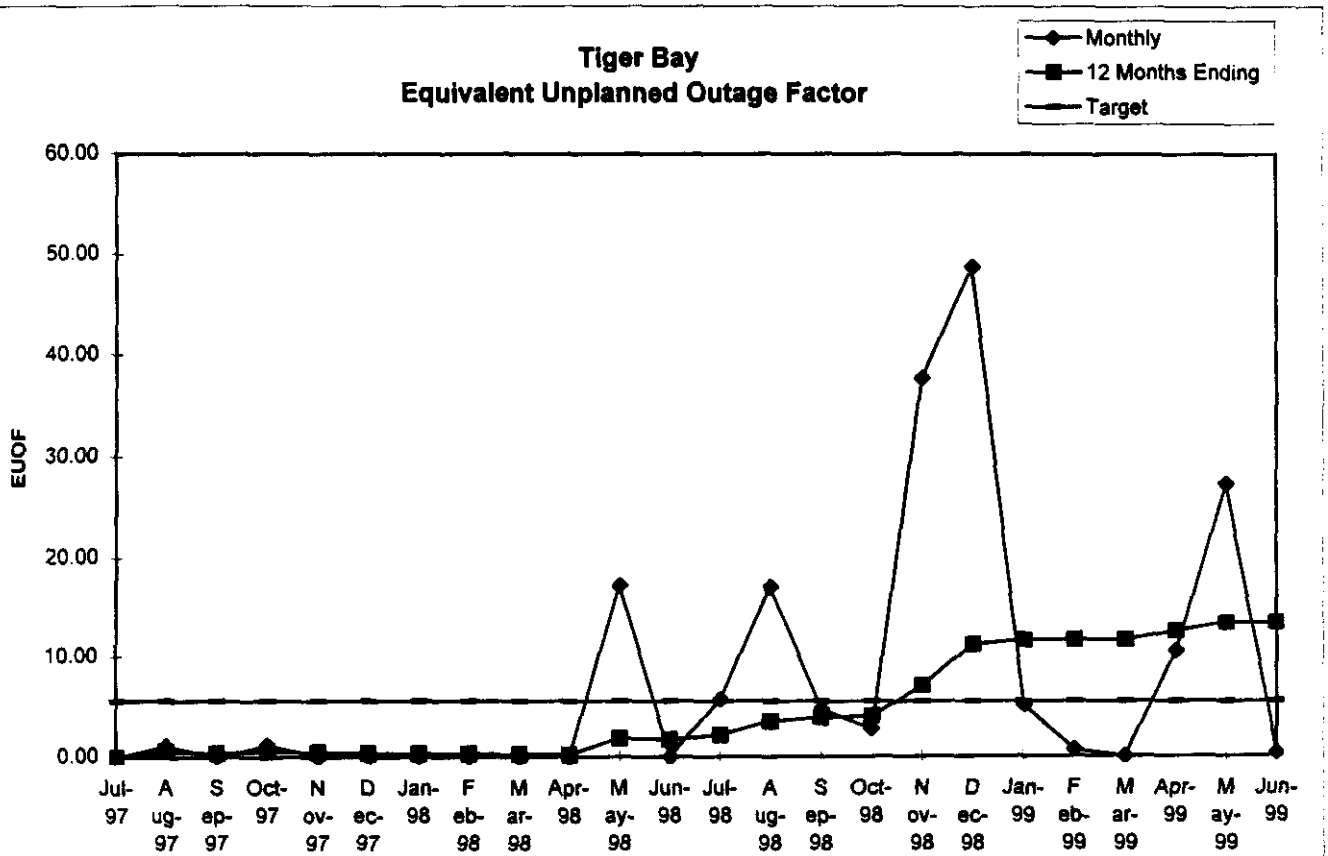
Jun-99


Tiger Bay
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-97
Aug-97
Sep-97
Oct-97
Nov-97
Dec-97
Jan-98
Feb-98
Mar-98
Apr-98
May-98
Jun-98
Jul-98
Aug-98
Sep-98
Oct-98
Nov-98
Dec-98
Jan-99
Feb-99
Mar-99
Apr-99
May-99
Jun-99

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990001-EI EXHIBIT NO. 10
COMPANY/
WITNESS: Backman
DATE 11-22-99

10

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

MARIANNA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	5,750,916		287,546	2.00000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	4,552,518		287,546	1.58323
10a	Demand Costs of Purchased Power	4,162,158	*		
10b	Transformation Energy & Customer Costs of Purchased Power	390,360	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	10,303,434		287,546	3.58323
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	10,303,434		287,546	3.58323
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	10,303,434		287,546	3.58323
21	Net Unbilled Sales	(14)	*	(0)	(0.00001)
22	Company Use	8,958	*	250	0.00330
23	T & D Losses	566,666	*	15,814	0.20873
24	SYSTEM MWH SALES	10,303,434		271,482	3.79525
25	Less Total Demand Cost Recovery	4,162,158	***		
26	Jurisdictional MWH Sales	6,141,276		271,482	2.26213
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	6,141,276		271,482	2.26213
28	GPIF **				
29	TRUE-UP **	(149,299)		271,482	(0.05499)
30	TOTAL JURISDICTIONAL FUEL COST	5,991,977		271,482	2.20714
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				2.20873
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH				2.209

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

EXHIBIT NO._____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 1 OF 20

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

MARIANNA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	125,713,537	55.052614%	52,135.1	1.089	1.000	56,775.1	125,713,537	54.67%	46.31%
35	GS	22,762,535	57.194949%	9,086.3	1.089	1.000	9,895.0	22,762,535	9.53%	8.38%
36	GSD	86,267,027	77.730883%	25,338.3	1.083	1.000	27,441.4	86,267,027	26.42%	31.78%
37	GSLD	33,202,935	83.217644%	9,109.3	1.038	1.000	9,455.5	33,202,935	9.10%	12.23%
38	OL	2,387,688	296.003708%	184.2	1.089	1.000	200.6	2,387,688	0.19%	0.88%
39	SL	1,148,412	296.003708%	88.6	1.089	1.000	96.5	1,148,412	0.09%	0.42%
40	TOTAL	271,482,134		95,941.8			103,864.1	271,482,134	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	50.47%	3.56%	54.03%	$2,248,814	0.01789	0.01790	0.02209	$0.03999
42	GS	8.80%	0.64%	9.44%	392,908	0.01726	0.01727	0.02209	$0.03936
43	GSD	24.39%	2.44%	26.83%	1,116,707	0.01294	0.01295	0.02209	$0.03504
44	GSLD	8.40%	0.94%	9.34%	388,746	0.01171	0.01172	0.02209	$0.03381
45	OL	0.18%	0.07%	0.25%	10,405	0.00436	0.00436	0.02209	$0.02645
46	SL	0.08%	0.03%	0.11%	4,578	0.00399	0.00399	0.02209	$0.02608
47	TOTAL	92.32%	7.68%	100.00%	$4,162,158				

(2) From Gulf Power Co. 1995 Load Research results.
(4) From Fernandina Rate Case.

EXHIBIT NO._____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 2 OF 20

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTH ACTUAL AND FOUR MONTHS ESTIMATED

Marianna Division

Over-recovery of purchased power costs for the period January 1999 - December 1999. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 1999)(Estimated)	$	149,299
Estimated kilowatt hour sales for the months of January 2000 - December 2000 as per estimate filed with the Commission		271,482,000
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2000 - December 2000		0.05499

Exhibit No._____
DOCKET NO. 990001-EI
Florida Public Utilities Company
(GMB-2)
Page 3 of 20

CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTH ACTUAL AND FOUR MONTHS ESTIMATED

MARIANNA DIVISION

			Actual JANUARY 1999	Actual FEBRUARY 1999	Actual MARCH 1999	Actual APRIL 1999	Actual MAY 1999	Actual JUNE 1999	SUB TOTAL
Total System Sales - KWH			23,507,795	18,936,576	20,047,704	19,075,344	20,795,524	24,838,564	127,201,507
Total System Purchases - KWH			24,109,295	19,939,804	20,621,289	22,033,338	24,431,953	27,151,755	138,287,434
System Billing Demand - KW			64,320	50,754	43,132	47,361	52,772	57,690	316,029
Purchased Power Rates:									
Base Fuel Costs - $/KWH			0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	
Demand and Non-Fuel:									
Demand Charge - $/KW			6.57	6.57	6.57	6.57	6.57	6.57	
Customer Charge - $			550.00	550.00	550.00	550.00	550.00	550.00	
Transformation Charge			31,980	31,980	31,980	31,979	31,980	31,980	
Purchased Power Costs:									
Base Fuel Costs			494,241	408,766	422,736	451,683	500,855	556,611	2,834,892
Subtotal Fuel Costs			494,241	408,766	422,736	451,683	500,855	556,611	2,834,892
Demand and Non-Fuel Costs:									
Demand Charge			422,582	333,453	283,377	311,162	346,712	379,023	2,076,309
Customer Charge			550	550	550	550	550	550	3,300
Transformation Charge			31,980	31,980	31,980	31,979	31,980	31,980	191,879
Subtotal Demand & Non-Fuel Costs			455,112	365,983	315,907	343,691	379,242	411,553	2,271,488
Total System Purchased Power Costs			949,353	774,749	738,643	795,374	880,097	968,164	5,106,380
Sales Revenues									
Fuel Adjustment Revenues:		Rate							
Residential	RS	0.04074	484,116	345,191	373,859	329,687	358,398	453,959	2,345,210
Commercial	GS	0.04011	75,832	64,320	68,731	69,086	77,193	93,627	448,789
Commercial	GSD	0.03581	243,515	214,625	230,312	217,860	237,210	267,103	1,410,625
Industrial	GSLD	0.03459	91,418	89,036	84,205	99,671	108,736	124,433	597,499
Residential	OL,OL-2	0.02728	5,328	5,342	5,346	5,441	5,468	5,719	32,644
Other	SL-1,SL-2,SL-3	0.02693	2,594	2,621	2,594	2,595	2,594	2,594	15,592
Total Fuel Revenues			902,803	721,135	765,047	724,340	789,599	947,435	4,850,359
Non-Fuel Revenues			498,740	430,984	444,465	424,230	444,195	489,308	2,731,922
Total Sales Revenue			1,401,543	1,152,119	1,209,512	1,148,570	1,233,794	1,436,743	7,582,281
KWH Sales:									
Residential	RS		11,882,482	8,472,355	9,175,973	8,091,857	8,796,496	11,142,077	57,561,240
Commercial	GS		1,890,604	1,603,594	1,713,565	1,722,405	1,924,542	2,334,262	11,188,972
Commercial	GSD		6,800,185	5,993,432	6,431,486	6,083,780	6,624,126	7,458,902	39,391,911
Industrial	GSLD		2,642,916	2,574,048	2,434,368	2,881,488	3,143,576	3,597,362	17,273,758
Residential	OL,OL-2		195,296	195,817	195,970	199,459	200,447	209,654	1,196,643
Other	SL-1,SL-2,SL-3		96,312	97,330	96,342	96,355	96,337	96,307	578,983
Total KWH Sales			23,507,795	18,936,576	20,047,704	19,075,344	20,785,524	24,838,564	127,191,507
True-up Calculation:									
Fuel Revenues			902,803	721,135	765,047	724,340	789,599	947,435	4,850,359
True-up Provision			(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(155,454)
Gross Receipts Tax Refund			0	0	0	0	0	0	0
Fuel Revenue			928,712	747,044	790,956	750,249	815,508	973,344	5,005,813
Total Purchased Power Costs			949,353	774,749	738,643	795,374	880,097	968,164	5,106,380
True-up Provision for the Period			(20,641)	(27,705)	52,313	(45,125)	(64,589)	5,180	(100,567)
Interest Provision for the Period			1,164	961	916	825	502	287	4,655
True-up and Interest Provision Beginning of Period			310,906	265,520	212,867	240,187	169,978	79,982	310,906
True-up Collected or (Refunded)			(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(155,454)
End of Period, Net True-up			265,520	212,867	240,187	169,978	79,982	59,540	59,540
10% Rule Interest Provision:									1.17%
Beginning True-up Amount			310,906	265,520	212,867	240,187	169,978	79,982	
Ending True-up Amount Before Interest			264,356	211,906	239,271	169,153	79,480	59,253	
Total Beginning and Ending True-up			575,262	477,426	452,138	409,340	249,458	139,235	
Average True-up Amount			287,631	238,713	226,069	204,670	124,729	69,618	
Average Annual Interest Rate			4.8550%	4.8300%	4.8650%	4.8400%	4.8250%	4.9500%	
Monthly Average Interest Rate			0.4046%	0.4025%	0.4054%	0.4033%	0.4021%	0.4125%	
Interest Provision			1,164	961	916	825	502	287	

CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTH ACTUAL AND FOUR MONTHS ESTIMATED

MARIANNA DIVISION			Actual JULY 1999	Actual AUGUST 1999	Estimated SEPTEMBE 1999	Estimated OCTOBER 1999	Estimated NOVEMBER 1999	Estimated DECEMBER 1999	Total
Total System Sales - KWH			26,960,579	30,842,368	28,423,720	23,004,478	19,373,645	21,982,868	277,789,165
Total System Purchases - KWH			30,898,449	33,764,118	26,944,600	22,236,529	21,032,041	23,623,342	296,786,513
System Billing Demand - KW			62,983	67,559	57,593	47,781	47,990	52,865	652,800
Purchased Power Rates:									
Base Fuel Costs - $/KWH			0.02050	0.02050	0.02050	0.02050	0.02050	0.02050	
Demand and Non-Fuel:									
Demand Charge - $/KW			6.57	6.57	6.57	6.57	6.57	6.57	
Customer Charge - $			550.00	550.00	550.00	550.00	550.00	550.00	
Transformation Charge			31,980.00	31,980	31,980	31,980	31,980	31,980	
Purchased Power Costs:									
Base Fuel Costs			633,418	692,164	552,364	455,849	431,157	484,279	6,084,123
Subtotal Fuel Costs			633,418	692,164	552,364	455,849	431,157	484,279	6,084,123
Demand and Non-Fuel Costs:									
Demand Charge			413,798	443,862	378,386	313,921	315,294	347,323	4,288,893
Customer Charge			550	550	550	550	550	550	6,600
Transformation Charge			31,980	31,980	31,980	31,980	31,980	31,980	383,759
Subtotal Demand & Non-Fuel Costs			446,328	476,392	410,916	346,451	347,824	379,853	4,679,252
Total System Purchased Power Costs			1,079,746	1,168,556	963,280	802,300	778,981	864,132	10,763,375
Sales Revenues									
Fuel Adjustment Revenues:		Rate							
Residential	RS	0.04074	504,195	601,685	523,367	393,008	327,392	420,387	5,115,244
Commercial	GS	0.04011	96,920	111,448	95,034	81,314	69,133	71,288	973,926
Commercial	GSD	0.03581	287,961	318,824	323,127	276,497	233,820	239,802	3,090,656
Industrial	GSLD	0.03459	132,876	141,568	135,060	115,162	97,011	100,671	1,319,847
Residential	OL,OL-2	0.02728	5,185	5,535	5,022	5,022	5,022	5,022	63,452
Other	SL-1,SL-2,SL-3	0.02693	2,592	2,589	2,579	2,579	2,579	2,579	31,089
Total Fuel Revenues			1,029,729	1,181,649	1,084,189	873,582	734,957	839,749	10,594,214
Non-Fuel Revenues			407,014	574,582	559,981	479,278	427,673	469,011	5,649,461
Total Sales Revenue			1,436,743	1,756,231	1,644,170	1,352,860	1,162,630	1,308,760	16,243,675
KWH Sales:									
Residential	RS		12,375,060	14,768,838	12,846,525	9,646,745	8,036,141	10,318,766	125,553,315
Commercial	GS		2,416,361	2,778,559	2,369,340	2,027,280	1,723,579	1,777,300	24,281,391
Commercial	GSD		8,041,360	8,903,217	9,023,372	7,721,227	6,529,452	6,696,510	86,307,049
ndustrial	GSLD		3,841,468	4,092,736	3,904,599	3,329,342	2,804,589	2,910,408	38,156,900
Residential	OL,OL-2		190,083	202,896	184,107	184,107	184,107	184,107	2,326,050
Other	SL-1,SL-2,SL-3		96,247	96,122	95,777	95,777	95,777	95,777	1,154,460
Total KWH Sales			26,960,579	30,842,368	28,423,720	23,004,478	19,373,645	21,982,868	277,779,165
True-up Calculation:									
Fuel Revenues			1,029,729	1,181,649	1,084,189	873,582	734,957	839,749	10,594,214
True-up Provision			(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(310,908)
Gross Receipts Tax Refund			0	0	0	0	0	0	0
Fuel Revenue			1,055,638	1,207,558	1,110,098	899,491	760,866	865,658	10,905,122
Total Purchased Power Costs			1,079,746	1,168,556	963,280	802,300	778,981	864,132	10,763,375
True-up Provision for the Period			(24,108)	39,002	146,818	97,191	(18,115)	1,526	141,747
Interest Provision for the Period			146	70	362	780	843	698	7,554
True-up and Interest Provision									0
Beginning of Period			59,540	9,669	22,832	144,103	216,165	172,984	936,199
True-up Collected or (Refunded)			(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(25,909)	(310,908)
End of Period, Net True-up			9,669	22,832	144,103	216,165	172,984	149,299	149,299
10% Rule Interest Provision:									1.39%
Beginning True-up Amount			59,540	9,669	22,832	144,103	216,165	172,984	
Ending True-up Amount Before Interest			9,523	22,762	143,741	215,385	172,141	148,601	
Total Beginning and Ending True-up			69,063	32,431	166,573	359,488	388,306	321,585	
Average True-up Amount			34,532	16,216	83,287	179,744	194,153	160,793	
Average Annual Interest Rate			5.0750%	5.2100%	5.2100%	5.2100%	5.2100%	5.2100%	
Monthly Average Interest Rate			0.4229%	0.4342%	0.4342%	0.4342%	0.4342%	0.4342%	
Interest Provision			146	70	362	780	843	698	

EXHIBIT NO. _____
DOCKET NO. 980001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 5 OF 20

SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	6,084,123	5,995,767	88,356	1.5%	296,787	292,476	4,311	1.5%	2.05000	2.05000	0.00000	0.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	*4,679,252*	*4,590,542*	*88,710*	1.9%	296,787	292,476	4,311	1.5%	1.57664	1.56954	0.00710	0.5%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	10,763,375	10,586,309	177,066	1.7%	296,787	292,476	4,311	1.5%	3.62663	3.61955	0.00708	0.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					296,787	292,476	4,311	1.5%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Fuel Cost of Other Power Sales (A6)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES *(LINE 14 + 15 + 16 + 17)*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	10,763,375	10,586,309	177,066	1.7%	296,787	292,476	4,311	1.5%	3.62663	3.61955	0.00708	0.2%
21	Net Unbilled Sales	249,403 *	158,753 *	90,650	57.1%	6,877	4,386	2,491	56.8%	0.08978	0.05749	0.03229	56.2%
22	Company Use	9,067 *	9,049 *	18	0.2%	*250*	*250*	*0*	0.0%	0.00326	0.00328	(0.00002)	-0.6%
23	T & D Losses	430,517 *	423,451 *	7,066	1.7%	11,871	11,699	172	1.5%	0.15498	0.15335	0.00163	1.1%
24	SYSTEM KWH SALES	10,763,375	10,586,309	177,066	1.7%	277,789	276,141	1,648	0.6%	3.87465	3.83367	0.04098	1.1%
25	Wholesale KWH Sales												
26	*Jurisdictional KWH Sales*	10,763,375	10,586,309	177,066	1.7%	277,789	276,141	1,648	0.6%	3.87465	3.83367	0.04098	1.1%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	*0.00000*	*0.0%*
27	Jurisdictional KWH Sales Adjusted for Line Losses	10,763,375	10,586,309	177,066	1.7%	277,789	276,141	1,648	0.6%	3.87465	3.83367	0.04098	1.1%
28	GPIF**												
29	TRUE-UP**	(310,908)	(60,107)	(250,801)	417.3%	277,789	276,141	1,648	0.6%	(0.11192)	(0.02177)	(0.09015)	414.1%
30	TOTAL JURISDICTIONAL FUEL COST	10,452,467	10,526,202	(73,735)	-0.7%	277,789	276,141	1,648	0.6%	3.76274	3.81189	(0.04915)	-1.3%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									3.76545	3.81463	(0.04918)	-1.3%
33	FUEL FAC *ROUNDED TO NEAREST .001 (CENTS/KWH)*									3.765	3.815	(0.050)	-1.3%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 6 OF 20

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

LINE NO.			(a) 2000 JANUARY	(b) 2000 FEBRUARY	(c) ESTIMATED 2000 MARCH	(d) 2000 APRIL	(e) 2000 MAY	2000 JUNE	2000 JULY	2000 AUGUST	2000 SEPTEMBER	2000 OCTOBER	2000 NOVEMBER	(f) 2000 DECEMBER	(g) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		488,622	402,554	406,361	390,140	496,903	526,673	586,833	612,661	527,161	436,935	405,919	470,154	5,750,916	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		381,606	379,695	333,831	321,091	368,229	423,011	431,929	434,477	410,271	352,941	340,201	375,236	4,552,518	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		870,228	782,249	740,192	711,231	865,132	949,684	1,018,762	1,047,138	937,432	789,876	746,120	845,390	10,303,434	5
6	LESS: TOTAL DEMAND COST RECOVERY		349,076	347,165	301,301	288,561	335,699	390,481	399,399	401,947	377,741	320,411	307,671	342,706	4,162,158	6
7	*TOTAL OTHER COST TO BE RECOVERED*		521,152	435,084	438,891	422,670	529,433	559,203	619,363	645,191	559,691	469,465	438,449	502,684	6,141,276	7
7a	SYSTEM KWH SOLD (MWH)		23,540	21,346	19,687	17,709	19,187	24,463	26,822	27,462	27,965	22,610	19,044	21,647	271,482	7a
7b	COST PER KWH SOLD (CENTS/KWH)		2.2139	2.03825	2.22934	2.38675	2.75933	2.28591	2.30916	2.3494	2.0014	2.07636	2.30229	2.32219	2.26213	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		2.21390	2.03825	2.22934	2.38675	2.75933	2.28591	2.30916	2.34940	2.00140	2.07636	2.30229	2.32219	2.26213	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	(0.05499)	11
12	TOTAL		2.15891	1.98326	2.17435	2.33176	2.70434	2.23092	2.25417	2.29441	1.94641	2.02137	2.24730	2.26720	2.20714	12
13	REVENUE TAX FACTOR	0.00072	0.00155	0.00143	0.00157	0.00168	0.00195	0.00161	0.00162	0.00165	0.00140	0.00146	0.00162	0.00163	0.00159	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.16046	1.98469	2.17592	2.33344	2.70629	2.23253	2.25579	2.29606	1.94781	2.02283	2.24892	2.26883	2.20873	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.160	1.985	2.176	2.333	2.706	2.233	2.256	2.296	1.948	2.023	2.249	2.269	2.209	15

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 7 OF 20

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA DIVISION

PURCHASED POWER

(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2000	GULF POWER COMPANY	RE	24,431,078			24,431,078	2.000002	3.561971	488,622
FEBRUARY	2000	GULF POWER COMPANY	RE	20,127,706			20,127,706	1.999999	3.886429	402,554
MARCH	2000	GULF POWER COMPANY	RE	20,318,067			20,318,067	1.999998	3.643024	406,361
APRIL	2000	GULF POWER COMPANY	RE	19,506,987			19,506,987	2.000001	3.646032	390,140
MAY	2000	GULF POWER COMPANY	RE	24,845,141			24,845,141	2.000001	3.482097	496,903
JUNE	2000	GULF POWER COMPANY	RE	26,333,633			26,333,633	2.000001	3.606354	526,673
JULY	2000	GULF POWER COMPANY	RE	29,341,628			29,341,628	2.000001	3.472070	586,833
AUGUST	2000	GULF POWER COMPANY	RE	30,633,041			30,633,041	2.000001	3.418329	612,661
SEPTEMBER	2000	GULF POWER COMPANY	RE	26,358,034			26,358,034	2.000001	3.556532	527,161
OCTOBER	2000	GULF POWER COMPANY	RE	21,846,749			21,846,749	2.000000	3.615531	436,935
NOVEMBER	2000	GULF POWER COMPANY	RE	20,295,932			20,295,932	2.000002	3.676205	405,919
DECEMBER	2000	GULF POWER COMPANY	RE	23,507,718			23,507,718	1.999998	3.596223	470,154
TOTAL				287,545,714	0	0	287,545,714	2.000001	3.583233	5,750,916

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 8 OF 20

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

	JANUARY 2000	FEBRUARY 2000	MARCH 2000	APRIL 2000	MAY 2000	JUNE 2000	JULY 2000
BASE RATE REVENUES ** $	20.47	20.47	20.47	20.47	20.47	20.47	20.47
FUEL RECOVERY FACTOR CENTS/KWH	4.099	4.099	4.099	4.099	4.099	4.099	4.099
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	40.99	40.99	40.99	40.99	40.99	40.99	40.99
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	1.58	1.58
TOTAL REVENUES *** $	63.04	63.04	63.04	63.04	63.04	63.04	63.04

	AUGUST 2000	SEPTEMBER 2000	OCTOBER 2000	NOVEMBER 2000	DECEMBER 2000	PERIOD TOTAL
BASE RATE REVENUES ** $	20.47	20.47	20.47	20.47	20.47	245.68
FUEL RECOVERY FACTOR CENTS/KWH	4.099	4.099	4.099	4.099	4.099	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	40.99	40.99	40.99	40.99	40.99	491.88
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	18.96
TOTAL REVENUES *** $	63.04	63.04	63.04	63.04	63.04	756.52

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES:

CUSTOMER CHARGE	8.30
CENTS/KWH	12.13
CONSERVATION FACTOR	0.043
	20.47

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 9 OF 20

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	7,381,110	400,060	1.84500
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Non Fuel Cost of Purch Power (E2)	6,215,578	400,060	1.55366
10a	Demand Costs of Purchased Power	5,792,814 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	422,764 *		
11	Energy Payments to Qualifying Facilities (E8a)	89,760	4,800	1.87000
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	13,686,448	404,860	3.38054
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	13,686,448	404,860	3.38054
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	13,686,448	404,860	3.38054
21	Net Unbilled Sales	237 *	7	0.00006
22	Company Use	14,739 *	436	0.00382
23	T & D Losses	615,901 *	18,219	0.15948
24	SYSTEM MWH SALES	13,686,448	386,198	3.54389
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	13,686,448	386,198	3.54389
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	13,686,448	386,198	3.54389
27a	GSLD MWH Sales		108,000	
27b	Other Classes MWH Sales		278,198	
27c	GSLD CP KW		258,000 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	(744,736)	386,198	-0.19284
30	TOTAL JURISDICTIONAL FUEL COST	12,941,712	386,198	3.35106
30a	Demand Purchased Power Costs (Line 10a)	5,792,814 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	7,893,634 *		
30c	True up Over/Under Recovery (Line 29)	(744,736) *		

* For Informational Purposes Only
** *Calculation Based on Jurisdictional KWH Sales*

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPAN
(GMB-2)
PAGE 10 OF 20

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	5,792,814		
32	GSLD Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $6.18)	1,594,440	258,000 (KW)	$6.18 /KW
33	Balance to Other Classes	4,198,374	278,198	1.50913
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	7,893,634		
35	Total KWH Purchased (Line 12)		404,860	
36	Average Cost per KWH Purchased			1.94972
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			2.00820
38	GSLD Non-demand Costs (Line 27a x Line 37)	2,168,869	108,000	2.00821
39	Balance to Other Classes	5,724,765	278,198	2.05780
	GSLD PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD Demand Costs (Line 32)	1,594,440	258,000 (KW)	$6.18 /KW
40b	Revenue Tax Factor			1.01597
40c	GSLD Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.28 /KW
40d	Total Current GSLD Non-demand Costs(Line 38)	2,168,869	108,000	2.00821
40e	Total Non-demand Costs Including True-up	2,168,869	108,000	2.00821
40f	Revenue Tax Factor			1.01597
40g	GSLD Non-demand Costs Adjusted for Taxes & Rounded			2.04028
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	9,923,139	278,198	3.56693
41b	Less: Total Demand Cost Recovery	4,198,374 ***		
41c	Total Other Costs to be Recovered	5,724,765	278,198	2.05780
41d	Other Classes' Portion of True-up (Line 30c)	(744,736)	278,198	-0.26770
41e	Total Demand & Non-demand Costs Including True-up	4,980,029	278,198	1.79010
42	Revenue Tax Factor			1.01597
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			1.819

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 11 OF 20

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

FERNANDINA BEACH DIVISON

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	162,746,096	60.910%	61,002.5	1.089	1.000	66,431.7	162,746,096	65.67%	58.50%
45	GS	21,838,268	67.794%	7,354.5	1.089	1.000	8,009.1	21,838,268	7.92%	7.85%
46	GSD	92,108,425	85.426%	24,617.0	1.083	1.000	26,660.2	92,108,425	26.35%	33.11%
47	OL, SL, CSL	1,505,160	585.192%	58.7	1.089	1.000	63.9	1,505,160	0.06%	0.54%
48	TOTAL	278,197,949		93,032.7			101,164.9	278,197,949	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.01609	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
49	RS	60.62%	4.50%	65.12%	$2,733,981	0.01680	0.01707	0.01819	0.03526
50	GS	7.31%	0.60%	7.91%	332,091	0.01521	0.01545	0.01819	0.03364
51	GSD	24.32%	2.55%	26.87%	1,128,103	0.01225	0.01245	0.01819	0.03064
52	OL, SL, CSL	0.06%	0.04%	0.10%	4,198	0.00279	0.00283	0.01819	0.02102
53	TOTAL	92.31%	7.69%	100.00%	$4,198,374				

(2) From Florida Power & Light Co. 1995 Load Research results.
(4) From Fernandina Beach *Rate Case 881056-EI.*

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 12 OF 20

Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTHS ACTUAL AND FOUR MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 1999 - December 1999. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Nine Month Period ended December 1999.)(Estimated)	$	744,736
Estimated kilowatt hour sales for the months of January 2000 - December 2000 as per estimate filed with the Commission. (Excludes GSLD customers)		278,197,949
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2000 - December 2000.		0.26770

Exhibit No._____
DOCKET NO. 990001-EI
Florida Public Utilities Company
(GMB-2)

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTH ACTUAL AND FOUR MONTHS ESTIMATED
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH		Actual JANUARY 1999	Actual FEBRUARY 1999	Actual MARCH 1999	Actual APRIL 1999	Actual MAY 1999	Actual JUNE 1999	Sub Total
Total System Sales - KWH		34,280,479	30,439,020	35,670,804	32,986,093	30,824,424	42,243,061	206,443,881
CCA Purchases - KWH		118,400	35,300	122,100	51,200	81,700	29,000	437,700
JEA Purchases - KWH		32,682,921	31,357,087	37,203,219	34,338,046	31,925,107	46,081,895	213,588,275
System Billing Demand - KW		82,074	78,803	74,323	73,248	73,203	90,854	472,505
Purchased Power Rates:								
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01845	0.018450	0.018450	0.018450	0.018450	0.018450	
Fuel Adjustment - $/KWH		0.00000	0.000000	0.000000	0.000000	0.000000	0.000000	
Demand and Non-Fuel:								
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH		0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	
Purchased Power Costs:								
CCA Fuel Costs		2,214	660	2,283	957	1,528	542	8,184
JEA Base Fuel Costs		603,000	578,539	686,399	633,537	589,018	850,211	3,940,704
JEA Fuel Adjustment		0	0	0	0	0	0	0
Subtotal Fuel Costs		605,214	579,199	688,682	634,494	590,546	850,753	3,948,888
Demand and Non-Fuel Costs:								
Demand Charge		492,444	472,818	445,938	439,488	439,218	545,124	2,835,030
Customer Charge		225	225	225	225	225	225	1,350
Energy Charge		34,317	32,925	39,063	36,055	33,521	48,386	224,267
Subtotal Demand & Non-Fuel Costs		526,986	505,968	485,226	475,768	472,964	593,735	3,060,647
Total System Purchased Power Costs		1,132,200	1,085,167	1,173,908	1,110,262	1,063,510	1,444,488	7,009,535
Less Direct Billing To GSLD Class:								
Demand		141,862	145,039	236,962	139,817	148,581	200,497	1,012,758
Commodity		214,369	244,141	303,013	253,622	203,560	312,812	1,531,517
Net Purchased Power Costs		775,969	695,987	633,933	716,823	711,369	931,179	4,465,260
Sales Revenues								
Fuel Adjustment Revenues:	Rate							
RS	0.03703	528,543	359,175	422,880	406,616	406,444	559,927	2,683,585
GS	0.03541	67,409	55,914	61,220	64,113	69,803	82,202	400,661
GSD	0.03245	236,746	222,536	236,573	241,043	246,515	294,766	1,478,179
OL	0.02274	1,597	1,606	1,609	1,668	1,663	1,675	9,818
SL,CSL	0.02274	1,535	1,822	1,797	1,580	1,715	1,700	10,149
Total Fuel Revenues (Excl. GSLD)		835,830	641,053	724,079	715,020	726,140	940,270	4,582,392
GSLD Fuel Revenues		356,231	389,180	539,975	393,439	352,141	513,309	2,544,275
Non-Fuel Revenues		543,115	468,241	529,114	490,204	493,646	595,833	3,120,153
Total Sales Revenue		1,735,176	1,498,474	1,793,168	1,598,663	1,571,927	2,049,412	10,246,820
KWH Sales:								
RS		14,273,954	9,699,916	11,420,305	10,981,127	10,976,451	15,120,287	72,472,040
GS		1,903,439	1,576,847	1,728,670	1,810,376	1,971,032	2,321,156	11,313,520
GSD		7,295,315	6,857,452	7,290,006	7,427,737	7,596,354	9,083,214	45,550,078
GSLD		10,670,000	12,152,000	15,082,000	12,624,000	10,132,000	15,570,000	76,230,000
OL		70,240	70,654	70,788	73,346	73,142	73,651	431,821
SL,CSL		67,531	80,151	79,035	69,507	75,445	74,753	446,422
Total KWH Sales		34,280,479	30,439,020	35,670,804	32,986,093	30,824,424	42,243,061	206,443,881
True-up Calculation (Excl. GSLD):								
Fuel Revenues		835,830	641,053	724,079	715,020	726,140	940,270	4,582,392
True-up Provision		(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(202,146)
Gross Receipts Tax Refund		0	0	0	0	0	0	0
Fuel Revenue		869,521	674,744	757,770	748,711	759,831	973,961	4,784,538
Net Purchased Power Costs		775,969	695,987	633,933	716,823	711,369	931,179	4,465,260
True-up Provision for the Period		93,552	(21,243)	123,837	31,888	48,462	42,782	319,278
Interest Provision for the Period		1,757	1,765	1,856	2,032	2,060	2,171	11,641
True-up and Interest Provision Beginning of Period		404,297	465,915	412,746	504,748	504,977	521,808	404,297
True-up Collected or (Refunded)		(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(202,146)
End of Period, Net True-up		465,915	412,746	504,748	504,977	521,808	533,070	533,070
10% RULE Interest Provision:								11.94%
Beginning True-up Amount		404,297	465,915	412,746	504,748	504,977	521,808	
Ending True-up Amount Before Interest		464,158	410,981	502,892	502,945	519,748	530,899	
Total Beginning and Ending True-up		868,455	876,896	915,638	1,007,693	1,024,725	1,052,707	
Average True-up Amount		434,228	438,448	457,819	503,847	512,363	526,354	
Average Interest Rate		4.8550%	4.8300%	4.8650%	4.8400%	4.8250%	4.9500%	
Monthly Average Interest Rate		0.4046%	0.4025%	0.4054%	0.4033%	0.4021%	0.4125%	
Interest Provision		1,757	1,765	1,856	2,032	2,060	2,171	

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
JANUARY 1999 - DECEMBER 1999
BASED ON EIGHT MONTH ACTUAL AND FOUR MONTHS ESTIMATED
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH		Actual JULY 1999	Actual AUGUST 1999	Estimated SEPTEMBER 1999	Estimated OCTOBER 1999	Estimated NOVEMBER 1999	Estimated DECEMBER 1999	Total
Total System Sales - KWH		42,269,613	50,457,653	35,556,610	30,763,150	26,190,959	28,610,969	420,292,835
JSC Purchases - KWH		45,000	82,400	400,000	400,000	400,000	400,000	2,165,100
JEA Purchases - KWH		46,502,287	52,554,734	34,795,033	29,721,115	26,504,723	31,695,851	435,362,018
System Billing Demand - KW		92,019	96,410	90,000	72,595	63,965	76,982	964,476
Purchased Power Rates:								
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:								
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH		0.001050	0.001050	0.001050	0.001050	0.001050	0.001050	
Purchased Power Costs:								
CCA Fuel Costs		842	1,541	7,480	7,480	7,480	7,480	40,487
JEA Base Fuel Costs		857,968	969,636	641,968	548,355	489,012	584,788	8,032,431
JEA Fuel Adjustment		0	0	0	0	0	0	0
Subtotal Fuel Costs		858,810	971,177	649,448	555,835	496,492	592,268	8,072,918
Demand and Non-Fuel Costs:								
Demand Charge		552,114	578,460	540,000	435,570	383,790	461,892	5,786,856
Customer Charge		225	225	225	225	225	225	2,700
Energy Charge		48,827	55,182	36,535	31,207	27,830	33,281	457,129
Subtotal Demand & Non-Fuel Costs		601,166	633,867	576,760	467,002	411,845	495,398	6,246,685
Total System Purchased Power Costs		1,459,976	1,605,044	1,226,208	1,022,837	908,337	1,087,666	14,319,603
Less Direct Billing To GSLD Class:								
Demand		142,400	231,406	132,870	132,870	132,870	132,870	1,918,044
Commodity		265,516	331,137	164,674	164,671	164,667	164,672	2,786,854
Net Purchased Power Costs		1,052,060	1,042,501	928,664	725,296	610,800	790,124	9,614,705
Sales Revenues								
Fuel Adjustment Revenues:	Rate							
RS	0.03703	645,191	763,140	598,658	463,343	345,311	423,347	5,922,575
GS	0.03541	90,173	105,125	75,151	67,495	58,678	59,258	856,541
GSD	0.03245	289,939	333,646	290,063	260,111	223,258	232,870	3,108,066
OL	0.02274	1,683	1,638	1,259	1,259	1,259	1,259	18,175
SL,CSL	0.02274	1,700	1,693	1,671	1,671	1,671	1,671	20,226
Total Fuel Revenues (Excl. GSLD)		1,028,686	1,205,242	966,802	793,879	630,177	718,405	9,925,583
GSLD Fuel Revenues		407,916	562,543	297,544	297,541	297,537	297,542	4,704,898
Non-Fuel Revenues		630,450	715,790	587,944	520,320	458,436	491,903	6,524,996
Total Sales Revenue		2,067,052	2,483,575	1,852,290	1,611,740	1,386,150	1,507,850	21,155,477
KWH Sales:								
RS		17,424,119	20,609,426	16,167,422	12,513,104	9,325,497	11,432,955	159,944,563
GS		2,546,240	2,968,449	2,122,058	1,905,869	1,656,908	1,673,283	24,186,327
GSD		8,934,475	10,281,291	8,938,274	8,015,321	6,879,698	7,175,875	95,775,012
GSLD		13,216,000	16,482,000	8,200,000	8,200,000	8,200,000	8,200,000	138,728,000
OL		74,026	72,042	55,367	55,367	55,367	55,367	799,357
SL,CSL		74,753	74,445	73,489	73,489	73,489	73,489	889,576
Total KWH Sales		42,269,613	50,487,653	35,556,610	30,763,150	26,190,959	28,610,969	420,322,835
True-up Calculation (Excl. GSLD):								
Fuel Revenues		1,028,686	1,205,242	966,802	793,879	630,177	718,405	9,925,583
True-up Provision		(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(404,292)
Gross Receipts Tax Refund		0	0	0	0	0	0	0
Fuel Revenue		1,062,377	1,238,933	1,000,493	827,570	663,868	752,096	10,329,875
Net Purchased Power Costs		1,052,060	1,042,501	928,664	725,296	610,800	790,124	9,614,705
True-up Provision for the Period		10,317	196,432	71,829	102,274	53,068	(38,028)	715,170
Interest Provision for the Period		2,205	2,576	3,023	3,268	3,473	3,375	29,561
True-up and Interest Provision								
Beginning of Period		533,070	511,901	677,218	718,379	790,230	813,080	404,297
True-up Collected or (Refunded)		(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(33,691)	(404,292)
End of Period, Net True-up		511,901	677,218	718,379	790,230	813,080	744,736	744,736
10% RULE Interest Provision:								7.75%
Beginning True-up Amount		533,070	511,901	677,218	718,379	790,230	813,080	
Ending True-up Amount Before Interest		509,696	674,642	715,356	786,962	809,607	741,361	
Total Beginning and Ending True-up		1,042,766	1,186,543	1,392,574	1,505,341	1,599,837	1,554,441	
Average True-up Amount		521,383	593,272	696,287	752,671	799,919	777,221	
Average Interest Rate		5.0750%	5.2100%	5.2100%	5.2100%	5.2100%	5.2100%	
Monthly Average Interest Rate		0.4229%	0.4342%	0.4342%	0.4342%	0.4342%	0.4342%	
Interest Provision		2,205	2,576	3,023	3,268	3,473	3,375	

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 1999 - DECEMBER 1999

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	8,032,431	7,020,503	1,011,928	14.4%	435,362	380,515	54,847	14.4%	1.84500	1.84500	0.00000	0.0%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	6,246,685	6,081,302	165,383	2.7%	435,362	380,515	54,847	14.4%	1.43483	1.59818	(0.16335)	-10.2%
11 Energy Payments to Qualifying Facilities (A8a)	40,487	89,760	(49,273)	-54.9%	2,165	4,800	(2,635)	-54.9%	1.87007	1.87000	0.00007	0.0%
12 TOTAL COST OF PURCHASED POWER	14,319,603	13,191,565	1,128,038	8.6%	437,527	385,315	52,212	13.6%	3.27285	3.42358	(0.15073)	-4.4%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					437,527	385,315	52,212	13.6%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)												
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,319,603	13,191,565	1,128,038	8.6%	437,527	385,315	52,212	13.6%	3.27285	3.42358	(0.15073)	-4.4%
21 Net Unbilled Sales (A4)	(309,415) *	(198,465) *	(110,950)	55.9%	(9,454)	(5,797)	(3,657)	63.1%	(0.07362)	(0.05400)	(0.01962)	36.3%
22 Company Use (A4)	14,270 *	14,927 *	(657)	-4.4%	436	436	0	0.0%	0.00340	0.00406	(0.00066)	-16.3%
23 T & D Losses (A4)	859,189 *	791,497 *	67,692	8.6%	26,252	23,119	3,133	13.6%	0.20443	0.21534	(0.01091)	-5.1%
24 SYSTEM KWH SALES	14,319,603	13,191,565	1,128,038	8.6%	420,293	367,557	52,736	14.4%	3.40706	3.58898	(0.18192)	-5.1%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	14,319,603	13,191,565	1,128,038	8.6%	420,293	367,557	52,736	14.4%	3.40706	3.58898	(0.18192)	-5.1%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	14,319,603	13,191,565	1,128,038	8.6%	420,293	367,557	52,736	14.4%	3.40706	3.58898	(0.18192)	-5.1%
28 GPIF**												
29 TRUE-UP**	(404,292)	(126,712)	(277,580)	219.1%	420,293	367,557	52,736	14.4%	(0.09619)	(0.03447)	(0.06172)	179.1%
30 TOTAL JURISDICTIONAL FUEL COST	13,915,311	13,064,853	850,458	6.5%	420,293	367,557	52,736	14.4%	3.31086	3.55451	(0.24365)	-6.9%
31 Revenue Tax Factor									1.01597	1.01609	(0.00012)	0.0%
32 Fuel Factor Adjusted for Taxes									3.36373	3.61170	(0.24797)	-6.9%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									3.364	3.612	(0.248)	-6.9%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 16 OF 20

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH DIVISION

FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

LINE NO.		(a)	(b)	(c)	(d)	(e)	(f)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	LINE NO.
							ESTIMATED								
		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL PERIOD	
1	FUEL COST OF SYSTEM GENERATION													0	1
1a	NUCLEAR FUEL DISPOSAL													0	1a
2	FUEL COST OF POWER SOLD													0	2
3	FUEL COST OF PURCHASED POWER	617,457	542,199	549,194	519,614	620,440	662,355	754,427	736,174	672,586	580,154	512,913	613,597	7,381,110	3
3a	DEMAND & NON FUEL COST OF PUR POWER	539,311	551,102	487,552	457,423	503,631	562,908	565,802	558,751	584,502	478,124	408,735	517,737	6,215,578	3a
3b	QUALIFYING FACILITIES	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	89,760	3b
4	ENERGY COST OF ECONOMY PURCHASES													0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	1,164,248	1,100,781	1,044,226	984,517	1,131,551	1,232,743	1,327,709	1,302,405	1,264,568	1,065,758	929,128	1,138,814	13,686,448	5
5a	LESS: TOTAL DEMAND COST RECOVERY	371,076	387,150	323,202	294,756	335,226	392,118	389,772	383,760	413,130	312,012	246,450	349,722	4,198,374	5a
5b	TOTAL OTHER COST TO BE RECOVERED	793,172	713,631	721,024	689,761	796,325	840,625	937,937	918,645	851,438	753,746	682,678	789,092	9,488,074	5b
6	APPORTIONMENT TO GSLD CLASS	313,609	313,605	313,606	313,604	313,609	313,611	313,613	313,613	313,611	313,607	313,604	313,609	3,763,301	6
6a	BALANCE TO OTHER CLASSES	479,563	400,026	407,418	376,157	482,716	527,014	624,324	605,032	537,827	440,139	369,074	475,483	5,724,773	6a
6b	SYSTEM KWH SOLD (MWH)	33,125	31,153	28,953	26,959	28,801	33,828	37,858	38,280	37,287	32,306	27,563	30,085	386,198	6b
7	GSLD MWH SOLD	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	108,000	7
7a	BALANCE MWH SOLD OTHER CLASSES	24,125	22,153	19,953	17,959	19,801	24,828	28,858	29,280	28,287	23,306	18,563	21,085	278,198	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES	1.98783	1.80574	2.04189	2.09453	2.43784	2.12266	2.16343	2.06637	1.90132	1.88852	1.98822	2.25508	2.05781	7b
8	JURISDICTIONAL LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)	1.98783	1.80574	2.04189	2.09453	2.43784	2.12266	2.16343	2.06637	1.90132	1.88852	1.98822	2.25508	2.05781	9
10	GPIF (CENTS/KWH)														10
11	TRUE-UP (CENTS/KWH) (744,736)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	(0.26770)	11
12	TOTAL	1.72013	1.53804	1.77419	1.82683	2.17014	1.85496	1.89573	1.79867	1.63362	1.62082	1.72052	1.98738	1.79011	12
13	REVENUE TAX FACTOR 0.01597	0.02747	0.02456	0.02833	0.02917	0.03466	0.02962	0.03027	0.02872	0.02609	0.02588	0.02748	0.03174	0.02859	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES	1.74760	1.56260	1.80252	1.85600	2.20480	1.88458	1.92600	1.82739	1.65971	1.64670	1.74800	2.01912	1.81870	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH	1.748	1.563	1.803	1.856	2.205	1.885	1.926	1.827	1.66	1.647	1.748	2.019	1.819	15

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 17 OF 20

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH DIVISION

PURCHASED POWER

(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	33,466,478			33,466,478	1.845001	3.478848	617,457
FEBRUARY 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,387,503			29,387,503	1.844999	3.745745	542,199
MARCH 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	29,766,612			29,766,612	1.845000	3.508045	549,194
APRIL 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	28,163,379			28,163,379	1.844999	3.495735	519,614
MAY 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	33,628,173			33,628,173	1.845001	3.364890	620,440
JUNE 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,899,976			35,899,976	1.845001	3.433827	662,355
JULY 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	40,890,346			40,890,346	1.845000	3.246999	754,427
AUGUST 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	39,901,011			39,901,011	1.845001	3.264090	736,174
SEPTEMBER 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,454,520			36,454,520	1.845000	3.468892	672,586
OCTOBER 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,444,635			31,444,635	1.845002	3.389316	580,154
NOVEMBER 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	27,800,153			27,800,153	1.845001	3.342169	512,913
DECEMBER 2000	JACKSONVILLE ELECTRIC AUTHORITY	MS	33,257,307			33,257,307	1.844999	3.424252	613,597
TOTAL			400,060,093	0	0	400,060,093	1.845000	3.421098	7,381,110

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 18 OF 20

FLORIDA PUBLIC UTILITIES COMPANY

FERNANDINA BEACH DIVISION

PURCHASED POWER

ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
FEBRUARY	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MARCH	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
APRIL	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MAY	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JUNE	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JULY	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
AUGUST	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
SEPTEMBER	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
OCTOBER	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
NOVEMBER	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
DECEMBER	2000	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
TOTAL				4,800,000	0	0	4,800,000	0.000000	0.000000	89,760

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 19 OF 20

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2000 THROUGH DECEMBER 2000

	JANUARY 2000	FEBRUARY 2000	MARCH 2000	APRIL 2000	MAY 2000	JUNE 2000	JULY 2000
BASE RATE REVENUES ** $	19.23	19.23	19.23	19.23	19.23	19.23	19.23
FUEL RECOVERY FACTOR CENTS/KWH	3.750	3.750	3.750	3.750	3.750	3.750	3.750
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	37.50	37.50	37.50	37.50	37.50	37.50	37.50
GROSS RECEIPTS TAX	0.58	0.58	0.58	0.58	0.58	0.58	0.58
TOTAL REVENUES *** $	57.31	57.31	57.31	57.31	57.31	57.31	57.31

	AUGUST 2000	SEPTEMBER 2000	OCTOBER 2000	NOVEMBER 2000	DECEMBER 2000	PERIOD TOTAL
BASE RATE REVENUES ** $	19.23	19.23	19.23	19.23	19.23	230.72
FUEL RECOVERY FACTOR CENTS/KWH	3.750	3.750	3.750	3.750	3.750	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	37.50	37.50	37.50	37.50	37.50	450.00
GROSS RECEIPTS TAX	0.58	0.58	0.58	0.58	0.58	6.96
TOTAL REVENUES *** $	57.31	57.31	57.31	57.31	57.31	687.68

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES:

CUSTOMER CHARGE	7.00
CENTS/KWH	12.20
CONSERVATION FACTOR	0.027
	19.23

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 990001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: Michael F. Oaks
Exhibit No. _____ (MFO-1)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
COAL SUPPLIERS
April 1, 1998 - December 31, 1998

CONTRACT COAL	TONS PURCHASED(1)	
PEABODY CONTRACT	1,313,106	
DECKER	1,014,941	(2)
TOTAL CONTRACT	2,328,047	
SPOT COAL		
ISLAND CREEK	61,276	
SUGAR CAMP	60,065	
CONSOLIDATION	69,985	
KERR MCGEE	128,075	
PEABODY COALSALES	595,531	
GUASARE INTERNATIONAL COAL	102,606	
JIM WALTER	96,324	
CONSOL OF KENTUCKY	89,952	
SSM COAL	112,283	
GLENCORE	289,029	
IKERD BANDY	69,511	
TOTAL SPOT	1,674,637	
GRAND TOTAL	4,002,684	

(1) Excludes Plant Scherer: The inventory at Plant Scherer is reported on a BTU basis. No inventory of tons is maintained.
(2) Gulf Power Company's portion of Plant Daniel supply.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 11
COMPANY/
WITNESS: Oaks
DATE: 11-22-99

12

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: Michael F. Oaks
Exhibit No. _____ (MFO-1)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
PROJECTED VS ACTUAL FUEL COST OF SYSTEM NET GENERATION

	Cents/KWH Fuel Cost (1)		
Period Ending	**Projected**	**Actual**	**Difference %**
March 1990	1.9688	1.9930	1.23
September 1990	2.0672	2.1840	5.65
March 1991	2.1028	2.2128	5.23
September 1991	2.1184	2.1255	0.34
March 1992	1.9524	2.0660	6.84
September 1992	1.9448	2.0401	4.90
March 1993	1.9458	1.9425	(0.17)
September 1993	1.9924	2.0408	2.43
March 1994	1.9050	2.0498	7.60
September 1994	1.8662	1.9373	3.81
March 1995	1.8874	2.0388	8.02
September 1995	2.0456	2.0344	(0.55)
March 1996	1.9795	2.0743	4.79
September 1996	2.0405	1.9639	(3.75)
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5284	-	-
December 2000	1.6025		

(1) Line No. 1 from FPSC Schedule A-1.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 12
COMPANY
WITNESS: Oaks
DATE: 11-22-99

13

Florida Public Service Commission
Docket No. 990001-EI
Gulf Power Company
Witness: G. D. Fontaine
Exhibit No. ___ (GDF-1)

EXHIBIT I TO THE TESTIMONY OF

G. D. FONTAINE

IN FPSC DOCKET 990001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 990001-EI EXHIBIT NO. 13
COMPANY/
WITNESS: Fontaine
DATE: 11-22-99

I. CORRECTIONS TO REPORTED DATA FOR THE APRIL 1998 - SEPTEMBER 1998 PERIOD

Additions and Corrections to Outages Previously Reported
for the April 1998 - September 1998 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
07/98	Crist 6	Event Type	FOH	13.8	317.0	Incorrectly Reported
07/98	Crist 7	Event Type	FOH	31.9	504.0	Incorrectly Reported
06/98	Daniel 2	LR pf	PFOH	630.8	47.7	Incorrectly Reported

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for April 1998 - September 1998

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	1	04/11/98 - 04/26/98	384.0	04/17/98 - 04/28/98	253.7
Crist 7	2	03/21/98 - 04/05/98	119.0	None	0.0
Smith 1	3	05/16/98 - 05/31/98	384.0	06/04/98 - 06/13/98	215.9
Smith 1	4	09/19/98 - 09/27/98	216.0	09/18/98 - 09/25/98	152.4
Smith 2	5	02/28/98 - 05/10/98	959.0	02/27/98 - 05/15/98	1050.5
Daniel 1	6	03/07/98 - 04/19/98	455.0	None	0.0
Daniel 1	7	05/23/98 - 05/31/98	216.0	None	0.0
Daniel 1	8	09/12/98 - 12/13/98	456.0	09/11/98 - 12/13/98	458.5
Daniel 2	9	05/02/98 - 05/10/98	216.0	None	0.0

* Planned outage hours in the April 1998 - September 1998 period only.

Notes:

1. This outage was deferred one week and shortened because of system reserve requirements.
2. This outage was canceled because of planned work being completed during an extended forced outage in the preceding reporting period.
3. This outage was deferred until June and the work was completed quicker than forecasted.
4. This outage proceeded as scheduled.
5. This outage proceeded as scheduled and was lengthened to complete unforeseen work.
6. This outage was moved forward and completed in a preceding reporting period.
7. This outage was canceled because the planned work was completed during maintenance outages.
8. This outage proceeded as scheduled.
9. This outage was canceled because the planned work was completed during maintenance outages.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	0.7	34.3	57.2	13.8	0.0	38.9	144.9
EFOH	24.5	2.3	0.1	3.3	0.1	38.9	69.2
MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	253.7	0.0	0.0	0.0	0.0	0.0	253.7
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(144.9 + 69.2 + 0.0 + 0.0)}{(4391.0 - 253.7 - 0.0)}$$

EUOR = 0.0517

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 384.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(384.0 + 0.0517\ (4391.0 - 384.0 - 0.0))}{4391.0} \right] \times 100 = 86.5\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	22.3	4.8	162.3	31.9	166.1	78.9	466.3
EFOH	3.1	8.1	12.6	9.1	6.0	50.2	89.1
MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(466.3 + 89.1 + 0.0 + 0.0)}{(4391.0 - 0.0 - 0.0)}$$

EUOR = 0.1265

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 119.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(119.0 + 0.1265\ (4391.0 - 119.0 - 0.0))}{4391.0} \right] \times 100 = 85.0\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EFOH	1.6	2.1	0.0	0.4	0.6	2.3	7.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.2	0.0	0.0	0.0	0.0	0.0	0.2
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	0.0	0.0	215.9	0.0	0.0	152.4	368.3
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 7.0 + 0.0 + 0.2)}{(4391.0 - 368.3 - 0.0)}$$

$$EUOR = 0.0018$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 600.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(600.0 + 0.0018\ (4391.0 - 600.0 - 0.0))}{4391.0} \right] \times 100 = 86.2\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	0.0	227.6	12.8	6.3	0.0	0.0	246.7
EFOH	0.0	24.8	0.5	42.6	1.1	0.0	69.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	2.6	0.0	0.0	0.0	2.6
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	719.0	331.5	0.0	0.0	0.0	0.0	1050.5
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(246.7 + 69.0 + 0.0 + 2.6)}{(4391.0 - 1050.5 - 0.0)}$$

EUOR = 0.0953

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 959.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(959.0 + 0.0953\ (4391.0 - 959.0 - 0.0))}{4391.0} \right] \times 100 = 70.7\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	92.2	0.0	0.0	3.4	0.0	0.0	95.6
EFOH	14.3	14.8	32.1	47.8	17.0	16.9	142.9
MOH	0.0	0.0	0.0	72.1	0.0	0.0	72.1
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	0.0	0.0	0.0	0.0	0.0	458.5	458.5
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(95.6 + 142.9 + 72.1 + 0.0)}{(4391.0 - 458.5 - 0.0)}$$

EUOR = 0.0790

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1127.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1127.0 + 0.0790\ (4391.0 - 1127.0 - 0.0))}{4391.0} \right] \times 100 = 68.5\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for April 1998 - September 1998
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Apr	May	Jun	Jul	Aug	Sep	Total
FOH	0.0	0.0	0.0	0.0	98.1	130.5	228.6
EFOH	25.6	63.9	63.1	62.9	60.9	66.4	342.8
MOH	220.3	21.0	83.5	0.0	0.0	0.0	324.8
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(228.6 + 342.8 + 324.8 + 0.0)}{(4391.0 - 0.0 - 0.0)}$$

$$EUOR = 0.2041$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(216.0 + 0.2041\ (4391.0 - 216.0 - 0.0))}{4391.0} \right] \times 100 = 75.7\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for April 1998 - September 1998

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 6	85.2	86.5	87.0	7.22
Crist 7	87.0	85.0	82.4	-4.35
Smith 1	83.4	86.2	84.2	10.00
Smith 2	72.8	70.7	70.4	-8.75
Daniel 1	67.9	68.5	69.9	3.00
Daniel 2	91.1	75.7	89.3	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Refer to pages 3 through 8 of this schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours.
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Crist 6

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	88305.5	149614.0	138429.3	163439.2	164668.3	137602.3	842058.6
BTU/Lb*	12218.0	11846.1	12276.9	12060.5	11977.9	11903.7	12032.7
Coal, MMBTU	1078916.6	1772342.4	1699482.7	1971158.5	1972380.4	1637976.5	10132257.1
Oil, MMBTU	410.7	638.6	1157.6	616.0	889.2	644.9	4357.0
Gas, MMBTU	6174.0	6125.0	1344.0	995.0	0.0	1257.0	15895.0
Startup, MMBTU **	-4040.0	-4040.0	-4040.0	0.0	0.0	-4040.0	-16160.0
Total Fuel Consumption, MMBTU	1081461.3	1775066.0	1697944.3	1972769.5	1973269.6	1635838.4	10136349.1
Net MWH Generation***	102337	169835	160682	184127	180910	151770	949661
Average Net Operating Heat Rate	10568	10452	10567	10714	10907	10778	10674

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Crist 7

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	269958.0	298537.1	199207.7	264246.9	209958.8	224951.3	1466859.8
BTU/Lb*	11962.1	11809.2	12310.1	12017.4	11942.5	11911.6	11977.7
Coal, MMBTU	3229264.6	3525484.3	2452266.7	3175560.7	2507433.0	2679529.9	17569539.2
Oil, MMBTU	333.4	420.0	452.2	666.1	748.0	522.4	3142.1
Gas, MMBTU	2006.0	319.0	6084.0	1076.0	3670.0	2920.0	16075.0
Startup, MMBTU **	0.0	0.0	-2256.0	-2256.0	-6768.0	-4512.0	-15792.0
Total Fuel Consumption, MMBTU	3231604.0	3526223.3	2456546.9	3175046.8	2505083.0	2678460.3	17572964.3
Net MWH Generation***	315480	335210	240340	312843	242403	258743	1705019
Average Net Operating Heat Rate	10243	10519	10221	10149	10334	10352	10307

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Smith 1

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	88186.6	98265.9	65403.0	100605.2	101211.8	74839.8	528512.3
BTU/Lb*	11888.9	11995.0	12044.8	11706.5	11508.7	11683.7	11791.3
Coal, MMBTU	1048441.7	1178699.5	787766.1	1177734.8	1164816.2	874405.8	6231864.1
Oil, MMBTU	149.5	182.8	1331.5	255.6	202.0	2013.6	4135.0
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-964.0	0.0	0.0	-964.0	-1928.0
Total Fuel Consumption, MMBTU	1048591.2	1178882.3	788133.6	1177990.4	1165018.2	875455.4	6234071.1
Net MWH Generation***	103185	114787	77397	115257	114945	85742	611313
Average Net Operating Heat Rate	10162	10270	10183	10221	10135	10210	10198

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Smith 2

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	0.0	22357.8	109056.8	110822.8	120573.3	112784.5	475595.2
BTU/Lb*	0.0	11906.0	12057.5	11662.5	11440.4	11588.9	11690.8
Coal, MMBTU	0.0	266192.0	1314952.4	1292470.9	1379406.8	1307048.3	5560070.4
Oil, MMBTU	104.5	8941.3	1500.0	1123.7	303.9	600.9	12574.3
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-4760.0	0.0	0.0	0.0	0.0	-4760.0
Total Fuel Consumption, MMBTU	104.5	270373.3	1316452.4	1293594.6	1379710.7	1307649.2	5567884.7
Net MWH Generation***	0	25830	131525	129034	137943	131676	556008
Average Net Operating Heat Rate	0	10467	10009	10025	10002	9931	10014

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Daniel 1

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	275086.8	339968.7	325374.0	299342.0	350219.9	128164.6	1718156.0
BTU/Lb*	9383.6	9248.9	9263.7	9212.2	9305.4	9275.3	9280.4
Coal, MMBTU	2581304.5	3144336.5	3014167.1	2757598.4	3258936.3	1188765.1	15945107.9
Oil, MMBTU	5018.4	4.8	69.4	6211.4	2176.3	1255.2	14735.5
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-4777.4	0.0	0.0	-2388.7	0.0	0.0	-7166.1
Total Fuel Consumption, MMBTU	2581545.5	3144341.3	3014236.5	2761421.1	3261112.6	1190020.3	15952677.3
Net MWH Generation***	247583	303498	285918	263368	312346	114365	1527078
Average Net Operating Heat Rate	10427	10360	10542	10485	10441	10405	10447

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for April 1998 - September 1998

Daniel 2

	Apr	May	Jun	Jul	Aug	Sep	Total
Pounds Coal(000's)	221413.2	332223.1	301332.4	354762.1	300555.4	269094.8	1779381.0
BTU/Lb*	9397.2	9249.7	9251.1	9219.7	9311.9	9116.1	9252.6
Coal, MMBTU	2080664.1	3072964.0	2787656.2	3270800.1	2798741.8	2453095.1	16463921.3
Oil, MMBTU	3806.0	2624.5	2163.8	4.9	5728.9	3707.9	18036.0
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-2388.7	0.0	-2388.7	0.0	-4777.4	-2388.7	-11943.5
Total Fuel Consumption, MMBTU	2082081.4	3075588.5	2787431.3	3270805.0	2799693.3	2454414.3	16470013.8
Net MWH Generation***	204942	301482	268711	310738	265423	233899	1585195
Average Net Operating Heat Rate	10159	10202	10373	10526	10548	10493	10390

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Crist 6

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	10534	10558	10534	10655	10643	10542	
2.	Target Heat Rate at Actual Conditions**	10512	10476	10472	10620	10600	10445	
3.	Adjustment to Actual Heat Rate (1-2)	22	82	62	35	43	97	
4.	Actual Heat Rate (Page 2 of Sched. 3)	10568	10452	10567	10714	10907	10778	
5.	Adjusted Actual Heat Rate (4+3)	10590	10534	10629	10749	10950	10875	
6.	Net MWH Generation	102337	169835	160682	184127	180910	151770	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10732

* From page 18, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Crist 7

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	10247	10414	10221	10374	10216	10258	
2.	Target Heat Rate at Actual Conditions**	10231	10370	10262	10408	10280	10306	
3.	Adjustment to Actual Heat Rate (1-2)	16	44	-41	-34	-64	-48	
4.	Actual Heat Rate (Page 3 of Sched. 3)	10243	10519	10221	10149	10334	10352	
5.	Adjusted Actual Heat Rate (4+3)	10259	10563	10180	10115	10270	10304	
6.	Net MWH Generation	315480	335210	240340	312843	242403	258743	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10290

* From page 19, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Smith 1

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	10194	10141	10182	10253	10181	10198	
2.	Target Heat Rate at Actual Conditions**	10226	10136	10195	10261	10192	10202	
3.	Adjustment to Actual Heat Rate (1-2)	-32	5	-13	-8	-11	-4	
4.	Actual Heat Rate (Page 4 of Sched. 3)	10162	10270	10183	10221	10135	10210	
5.	Adjusted Actual Heat Rate (4+3)	10130	10275	10170	10213	10124	10206	
6.	Net MWH Generation	103185	114787	77397	115257	114945	85742	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10187

* From page 20, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Smith 2

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	-	10269	10348	10348	10349	10217	
2.	Target Heat Rate at Actual Conditions**	-	10220	10348	10342	10348	10223	
3.	Adjustment to Actual Heat Rate (1-2)	0	49	0	6	1	-6	
4.	Actual Heat Rate (Page 5 of Sched. 3)	0	10467	10009	10025	10002	9931	
5.	Adjusted Actual Heat Rate (4+3)	0	10516	10009	10031	10003	9925	
6.	Net MWH Generation	0	25830	131525	129034	137943	131676	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10016

* From page 21, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Daniel 1

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	10511	10547	10500	10500	10490	10535	
2.	Target Heat Rate at Actual Conditions**	10466	10469	10507	10511	10450	10447	
3.	Adjustment to Actual Heat Rate (1-2)	45	78	-7	-11	40	88	
4.	Actual Heat Rate (Page 6 of Sched. 3)	10427	10360	10542	10485	10441	10405	
5.	Adjusted Actual Heat Rate (4+3)	10472	10438	10535	10474	10481	10493	
6.	Net MWH Generation	247583	303498	285918	263368	312346	114365	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10481

* From page 22, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for April 1998 - September 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed January 12, 1998

Daniel 2

		Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
1.	Target Heat Rate*	10260	10340	10231	10232	10225	10371	
2.	Target Heat Rate at Actual Conditions**	10270	10334	10255	10261	10270	10395	
3.	Adjustment to Actual Heat Rate (1-2)	-10	6	-24	-29	-45	-24	
4.	Actual Heat Rate (Page 7 of Sched. 3)	10159	10202	10373	10526	10548	10493	
5.	Adjusted Actual Heat Rate (4+3)	10149	10208	10349	10497	10503	10469	
6.	Net MWH Generation	204942	301482	268711	310738	265423	233899	
7.	Adjusted Actual Heat Rate for April 1998 - September 1998 $=(\Sigma(5*6)/\Sigma 6)$							10369

* From page 23, schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Actual Values of
Target Heat Rate Equation Parameters
for April 1998 - September 1998

	Apr	May	Jun	Jul	Aug	Sep
Crist 6						
AKW * 10^{+3}	220.3	239.3	242.4	252.2	243.2	222.8
LSRF * 10^{+6}	53936.4	62390.1	63790.1	69142.6	64567.6	53820.9
Crist 7						
AKW • 10^{+3}	452.8	453.5	430.9	439.3	419.5	403.6
LSRF * 10^{+6}	210106.6	210275.2	194424.9	200913.8	185679.4	173620.4
Smith 1						
AKW * 10^{+3}	143.5	154.3	153.5	154.9	154.5	151.1
LSRF * 10^{+6}	21412.2	23918.0	23803.1	24080.4	23916.2	23057.1
Smith 2						
AKW * 10^{+3}	0.0	139.7	186.0	174.9	185.4	182.9
LSRF * 10^{+6}	0.0	21681.6	34801.6	31593.3	34425.6	33594.7
Daniel 1						
AKW * 10^{+3}	395.0	407.9	397.1	394.0	419.8	437.3
LSRF * 10^{+6}	168919.1	175152.5	165327.8	163282.9	183390.8	192707.1
Daniel 2						
AKW * 10^{+3}	411.0	417.0	422.2	417.7	410.9	396.8
LSRF * 10^{+6}	173655.3	175497.6	180626.4	175218.4	171644.1	160691.9

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [593.85 - 27.74 * JAN - 40.10 * MAR + 30.09 * JUL + 26.73 * AUG - 25.29 * OCT]
+ 5,067 + 0.01123 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [276.36 + 63.12 * MAY + 69.54 * JUL]
+ 9,621

Smith 1 ANOHR = 10^6 / AKW * [69.20 + 18.16 * JAN + 12.44 * FEB + 15.12 * MAR - 8.67 * MAY + 10.92 * JUL]
+ 9,744

Smith 2 ANOHR = 10^6 / AKW * [-18.22 + 16.52 * MAR - 13.41 * MAY - 22.58 * SEP - 13.92 * NOV]
+ 10,446

Daniel 1 ANOHR = 10^6 / AKW * [-103.81 - 44.15 * MAR - 40.19 * NOV]
+ 12,196 - 0.00343 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [218.47 + 30.22 * MAY + 42.12 * SEP]
+ 9,738

Where:

ANOHR	Average Net Operating Heat Rate, BTU/KWH
AKW	Average Kilowatt Load, KW
LSRF	Load Square Range Factor, KW^2
JAN	January, 0 if not January, 1 if January
FEB	February, 0 if not February, 1 if February
MAR	March, 0 if not March, 1 if March
APR	April, 0 if not April, 1 if April
MAY	May, 0 if not May, 1 if May
JUN	June, 0 if not June, 1 if June
JUL	July, 0 if not July, 1 if July
AUG	August, 0 if not August, 1 if August
SEP	September, 0 if not September, 1 if September
OCT	October, 0 if not October, 1 if October
NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for April 1998 - September 1998

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 6	10584	10732	10266	-3.00
Crist 7	10291	10290	9982	0.00
Smith 1	10197	10187	9891	0.00
Smith 2	10311	10016	10002	9.40
Daniel 1	10508	10481	10193	0.00
Daniel 2	10270	10369	9962	-1.03

* From page 5, Schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

** Refer to pages 8 through 13 of this schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

If [(2) - (3) - 75] > 0 then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If [(2) - (3) + 75] < 0 then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for April 1998 - September 1998

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 6	7.22	0.025	-3.00	0.105
Crist 7	-4.35	0.135	0.00	0.198
Smith 1	10.00	0.034	0.00	0.037
Smith 2	-8.75	0.008	9.40	0.037
Daniel 1	3.00	0.039	0.00	0.121
Daniel 2	-10.00	0.072	-1.03	0.191

Company GPIF Points = + 7.22 * 0.025 - 3.00 * 0.105
- 4.35 * 0.135 + 0.00 * 0.198
+ 10.00 * 0.034 + 0.00 * 0.037
- 8.75 * 0.008 + 9.40 * 0.037
+ 3.00 * 0.039 + 0.00 * 0.121
- 10.00 * 0.072 - 1.03 * 0.191
-0.90

Company reward/penalty = -0.90 points * $83728 per point

= ($75,355)

* From page 5, Schedule 3 of Exhibit to G. D. Fontaine's January 12, 1998 GPIF testimony in Docket 980001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE APRIL 1998 - SEPTEMBER 1998 PERIOD

CONTENTS	SCHEDULE 5 PAGE
GPIF Reward/Penalty Table (Actual)	3
GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)	4
Calculation of System Actual GPIF Points	5
Generating Performance Incentive Points Table	6 - 11
GPIF Unit Performance Summary	12
Actual Unit Performance Data	13
Historic Unit Performance Data	14 - 19
Planned Outage Schedules (Actual)	20

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: April 1998 - September 1998

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	4073	837
+ 9	3666	754
+ 8	3258	670
+ 7	2851	586
+ 6	2444	502
+ 5	2037	419
+ 4	1629	335
+ 3	1222	251
+ 2	815	167
+ 1	407	84
0	0	0
- 1	-523	-84
- 2	-1047	-167
- 3	-1570	-251
- 4	-2093	-335
- 5	-2617	-419
- 6	-3140	-502
- 7	-3663	-586
- 8	-4186	-670
- 9	-4710	-754
- 10	-5233	-837
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: April 1998 - September 1998

Line 1	Beginning of Period Balance of Common Equity	$420,572,032
	End of Month Balance of Common Equity:	
Line 2	Month of Apr '98	$409,256,566
Line 3	Month of May '98	$415,131,266
Line 4	Month of Jun '98	$419,836,438
Line 5	Month of Jul '98	$414,593,716
Line 6	Month of Aug '98	$424,703,091
Line 7	Month of Sep '98	$432,725,103
Line 8	Average Common Equity for the Period (sum of line 1 through line 7 divided by 7)	$419,545,459
Line 9	25 Basis Points	0.0025
Line 10	Revenue Expansion Factor	60.4524%
Line 11	Maximum Allowed Incentive Dollars (line 8 multiplied by line 9 divided by line 10 multiplied by 0.5)	$867,512
Line 12	Jurisdictional Sales (KWH)	5,355,886,805
Line 13	Total Territorial Sales (KWH)	5,549,305,803
Line 14	Jurisdictional Separation Factor (line 12 divided by line 13)	96.5145%
Line 15	Maximum Allowed Jurisdictional Incentive Dollars (line 11 multiplied by line 14)	$837,275

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Calculation of System Actual GPIF Points

Gulf Power Company

Period of: April 1998 - September 1998

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 6	EAF1	2.5%	7.22	0.181
Crist 6	ANOHR1	10.5%	-3.00	-0.315
Crist 7	EAF2	13.5%	-4.35	-0.587
Crist 7	ANOHR2	19.8%	0.00	0.000
Smith 1	EAF3	3.4%	10.00	0.340
Smith 1	ANOHR3	3.7%	0.00	0.000
Smith 2	EAF4	0.8%	-8.75	-0.070
Smith 2	ANOHR4	3.7%	9.40	0.348
Daniel 1	EAF5	3.9%	3.00	0.117
Daniel 1	ANOHR5	12.1%	0.00	0.000
Daniel 2	EAF6	7.2%	-10.00	-0.720
Daniel 2	ANOHR6	19.1%	-1.03	-0.197
Gulf Power GPIF Total		100.2%		-0.90

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	102	87.00	+ 10	428	10,266
+ 9	92	86.82	+ 9	385	10,290
+ 8	82	86.64	+ 8	342	10,315
+ 7	71	86.46	+ 7	300	10,339
+ 6	61	86.28	+ 6	257	10,363
+ 5	51	86.10	+ 5	214	10,388
+ 4	41	85.92	+ 4	171	10,412
+ 3	31	85.74	+ 3	128	10,436
+ 2	20	85.56	+ 2	86	10,460
+ 1	10	85.38	+ 1	43	10,485
				0	10,509
0	0	85.20	0	0	10,584
				0	10,659
- 1	(17)	84.93	- 1	(43)	10,683
- 2	(34)	84.66	- 2	(86)	10,708
- 3	(52)	84.39	- 3	(128)	10,732
- 4	(69)	84.12	- 4	(171)	10,756
- 5	(86)	83.85	- 5	(214)	10,781
- 6	(103)	83.58	- 6	(257)	10,805
- 7	(120)	83.31	- 7	(300)	10,829
- 8	(138)	83.04	- 8	(342)	10,853
- 9	(155)	82.77	- 9	(385)	10,878
- 10	(172)	82.50	- 10	(428)	10,902
Weighting Factor:		0.025	Weighting Factor:		0.105

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Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	549	90.10	+ 10	806	9,982
+ 9	494	89.79	+ 9	725	10,005
+ 8	439	89.48	+ 8	645	10,029
+ 7	384	89.17	+ 7	564	10,052
+ 6	329	88.86	+ 6	484	10,076
+ 5	275	88.55	+ 5	403	10,099
+ 4	220	88.24	+ 4	322	10,122
+ 3	165	87.93	+ 3	242	10,146
+ 2	110	87.62	+ 2	161	10,169
+ 1	55	87.31	+ 1	81	10,193
				0	10,216
0	0	87.00	0	0	10,291
				0	10,366
- 1	(99)	86.54	- 1	(81)	10,389
- 2	(198)	86.08	- 2	(161)	10,413
- 3	(297)	85.62	- 3	(242)	10,436
- 4	(396)	85.16	- 4	(322)	10,460
- 5	(495)	84.70	- 5	(403)	10,483
- 6	(593)	84.24	- 6	(484)	10,506
- 7	(692)	83.78	- 7	(564)	10,530
- 8	(791)	83.32	- 8	(645)	10,553
- 9	(890)	82.86	- 9	(725)	10,577
- 10	(989)	82.40	- 10	(806)	10,600
Weighting Factor:		0.135	Weighting Factor:		0.198

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	137	84.20	+ 10	150	9,891
+ 9	123	84.12	+ 9	135	9,914
+ 8	110	84.04	+ 8	120	9,937
+ 7	96	83.96	+ 7	105	9,960
+ 6	82	83.88	+ 6	90	9,983
+ 5	69	83.80	+ 5	75	10,007
+ 4	55	83.72	+ 4	60	10,030
+ 3	41	83.64	+ 3	45	10,053
+ 2	27	83.56	+ 2	30	10,076
+ 1	14	83.48	+ 1	15	10,099
				0	10,122
0	0	83.40	0	0	10,197
				0	10,272
- 1	(52)	83.26	- 1	(15)	10,295
- 2	(105)	83.12	- 2	(30)	10,318
- 3	(157)	82.98	- 3	(45)	10,341
- 4	(210)	82.84	- 4	(60)	10,364
- 5	(262)	82.70	- 5	(75)	10,388
- 6	(314)	82.56	- 6	(90)	10,411
- 7	(367)	82.42	- 7	(105)	10,434
- 8	(419)	82.28	- 8	(120)	10,457
- 9	(472)	82.14	- 9	(135)	10,480
- 10	(524)	82.00	- 10	(150)	10,503
Weighting Factor:		0.034	Weighting Factor:		0.037

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Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	31	74.40	+ 10	149	10,002
+ 9	28	74.24	+ 9	134	10,025
+ 8	25	74.08	+ 8	119	10,049
+ 7	22	73.92	+ 7	104	10,072
+ 6	19	73.76	+ 6	89	10,096
+ 5	16	73.60	+ 5	75	10,119
+ 4	12	73.44	+ 4	60	10,142
+ 3	9	73.28	+ 3	45	10,166
+ 2	6	73.12	+ 2	30	10,189
+ 1	3	72.96	+ 1	15	10,213
				0	10,236
0	0	72.80	0	0	10,311
				0	10,386
- 1	(4)	72.56	- 1	(15)	10,409
- 2	(8)	72.32	- 2	(30)	10,433
- 3	(11)	72.08	- 3	(45)	10,456
- 4	(15)	71.84	- 4	(60)	10,480
- 5	(19)	71.60	- 5	(75)	10,503
- 6	(23)	71.36	- 6	(89)	10,526
- 7	(27)	71.12	- 7	(104)	10,550
- 8	(30)	70.88	- 8	(119)	10,573
- 9	(34)	70.64	- 9	(134)	10,597
- 10	(38)	70.40	- 10	(149)	10,620
Weighting Factor:		0.008	Weighting Factor:		0.037

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Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	157	69.90	+ 10	493	10,193
+ 9	141	69.70	+ 9	444	10,217
+ 8	126	69.50	+ 8	394	10,241
+ 7	110	69.30	+ 7	345	10,265
+ 6	94	69.10	+ 6	296	10,289
+ 5	79	68.90	+ 5	247	10,313
+ 4	63	68.70	+ 4	197	10,337
+ 3	47	68.50	+ 3	148	10,361
+ 2	31	68.30	+ 2	99	10,385
+ 1	16	68.10	+ 1	49	10,409
				0	10,433
0	0	67.90	0	0	10,508
				0	10,583
- 1	(15)	67.61	- 1	(49)	10,607
- 2	(30)	67.32	- 2	(99)	10,631
- 3	(45)	67.03	- 3	(148)	10,655
- 4	(60)	66.74	- 4	(197)	10,679
- 5	(76)	66.45	- 5	(247)	10,703
- 6	(91)	66.16	- 6	(296)	10,727
- 7	(106)	65.87	- 7	(345)	10,751
- 8	(121)	65.58	- 8	(394)	10,775
- 9	(136)	65.29	- 9	(444)	10,799
- 10	(151)	65.00	- 10	(493)	10,823
Weighting Factor:		0.039	Weighting Factor:		0.121

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Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: April 1998 - September 1998

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	295	92.30	+ 10	776	9,962
+ 9	266	92.18	+ 9	698	9,985
+ 8	236	92.06	+ 8	621	10,009
+ 7	207	91.94	+ 7	543	10,032
+ 6	177	91.82	+ 6	466	10,055
+ 5	148	91.70	+ 5	388	10,079
+ 4	118	91.58	+ 4	310	10,102
+ 3	89	91.46	+ 3	233	10,125
+ 2	59	91.34	+ 2	155	10,148
+ 1	30	91.22	+ 1	78	10,172
				0	10,195
0	0	91.10	0	0	10,270
				0	10,345
- 1	(56)	90.92	- 1	(78)	10,368
- 2	(111)	90.74	- 2	(155)	10,392
- 3	(167)	90.56	- 3	(233)	10,415
- 4	(223)	90.38	- 4	(310)	10,438
- 5	(279)	90.20	- 5	(388)	10,462
- 6	(334)	90.02	- 6	(466)	10,485
- 7	(390)	89.84	- 7	(543)	10,508
- 8	(446)	89.66	- 8	(621)	10,531
- 9	(501)	89.48	- 9	(698)	10,555
- 10	(557)	89.30	- 10	(776)	10,578
Weighting Factor:		0.072	Weighting Factor:		0.191

Issued by: T. J. Bowden

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Docket No.: 990001-EI
Order No.:

GPIF Unit Performance Summary

Gulf Power Company

Period of: April 1998 - September 1998

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 6	2.5	85.2	87.0	82.5	102	-172	86.5	$74
Crist 7	13.5	87.0	90.1	82.4	549	-989	85.0	($430)
Smith 1	3.4	83.4	84.2	82.0	137	-524	86.2	$137
Smith 2	0.8	72.8	74.4	70.4	31	-38	70.7	($33)
Daniel 1	3.9	67.9	69.9	65.0	157	-151	68.5	$47
Daniel 2	7.2	91.1	92.3	89.3	295	-557	75.7	($557)
Total:	31.3							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 6	10.5	10,584	74.6	10,902	10,266	$428	($428)	10,732	($128)
Crist 7	19.8	10,291	89.0	10,600	9,982	$806	($806)	10,290	$0
Smith 1	3.7	10,197	96.8	10,503	9,891	$150	($150)	10,187	$0
Smith 2	3.7	10,311	96.1	10,620	10,002	$149	($149)	10,016	$140
Daniel 1	12.1	10,508	83.5	10,823	10,193	$493	($493)	10,481	$0
Daniel 2	19.1	10,270	90.3	10,578	9,962	$776	($776)	10,369	($80)
Total:	68.9								

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Filed: April 1, 1999
Suspended:
Effective: April 1, 1999
Docket No.: 990001-EI
Order No.:

Actual Unit Performance Data

Gulf Power Company

Period of: April 1998 - September 1998

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 6	89.3	-2.8	86.5
Crist 7	87.4	-2.4	85.0
Smith 1	91.4	-5.2	86.2
Smith 2	68.8	1.9	70.7
Daniel 1	82.5	-14.0	68.5
Daniel 2	79.6	-3.9	75.7

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 6	10,674	58	10,732
Crist 7	10,307	-17	10,290
Smith 1	10,198	-11	10,187
Smith 2	10,014	2	10,016
Daniel 1	10,447	34	10,481
Daniel 2	10,390	-21	10,369

* Refer to pages 3 through 8, Schedule 2.

** Refer to pages 8 through 13, Schedule 3.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	CRIST 6	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	61.2	95.1	92.0	97.7	100.0	89.2	89.3
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	464.6	709.7	662.8	730.2	744.0	681.1	3992.4
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	254.4	34.3	57.2	13.8	0.0	38.9	398.6
6.	POH	253.7	0.0	0.0	0.0	0.0	0.0	253.7
7.	FOH	0.7	34.3	57.2	13.8	0.0	38.9	144.9
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	93.9	6.7	0.2	12.8	0.9	106.3	220.8
10.	LR pf (MW)	82.6	110.2	191.0	80.6	50.6	116.1	99.4
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	317.0	317.0	317.0	317.0	317.0	317.0	317.0
14.	Oper MBtu	1081461	1775066	1697944	1972769	1973270	1635838	10136348
15.	Net Gen (MWH)	102337	169835	160682	184127	180910	151770	949661
16.	ANOHR (Btu/KWH)	10568	10452	10567	10714	10907	10778	10674
17.	NOF %	69.5	75.5	76.5	79.5	76.7	70.3	75.0
18.	NPC (MW)	317.0	317.0	317.0	317.0	317.0	317.0	317.0
19.	ANOHR Equation	10^6 / AKW * [593.85 - 27.74 * JAN - 40.10 * MAR + 30.09 * JUL + 26.73 * AUG - 25.29 * OCT] + 5,067 + 0.01123 * LSRF / AKW						

Issued by: T. J. Bowden

Filed: April 1, 1999
Suspended:
Effective: April 1, 1999
Docket No.: 990001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	CRIST 7	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	96.5	98.3	75.7	94.5	76.9	82.1	87.4
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	696.7	739.2	557.7	712.1	577.9	641.1	3924.7
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	22.3	4.8	162.3	31.9	166.1	78.9	466.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	22.3	4.8	162.3	31.9	166.1	78.9	466.3
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	13.6	46.1	58.7	41.1	70.9	305.2	535.6
10.	LR pf (MW)	113.6	88.7	108.1	112.0	42.5	82.9	83.8
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	504.0	504.0	504.0	504.0	504.0	504.0	504.0
14.	Oper MBtu	3231604	3526223	2456547	3175047	2505083	2678460	17572964
15.	Net Gen (MWH)	315480	335210	240340	312843	242403	258743	1705019
16.	ANOHR (Btu/KWH)	10243	10519	10221	10149	10334	10352	10307
17.	NOF %	89.8	90.0	85.5	87.2	83.2	80.1	86.2
18.	NPC (MW)	504.0	504.0	504.0	504.0	504.0	504.0	504.0
19.	ANOHR Equation	10^6 / AKW * [276.36 + 63.12 * MAY + 69.54 * JUL] + 9,621						

Issued by: T. J. Bowden

Filed: April 1, 1999
Suspended:
Effective: April 1, 1999
Docket No.: 990001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	SMITH 1	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	99.8	99.7	70.0	99.9	99.9	78.5	91.4
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	719.0	744.0	504.1	744.0	744.0	567.6	4022.7
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	215.9	0.0	0.0	152.4	368.3
6.	POH	0.0	0.0	215.9	0.0	0.0	152.4	368.3
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	9.5	12.8	0.0	24.6	2.2	14.3	63.4
10.	LR pf (MW)	26.7	26.0	0.0	2.7	42.4	26.1	17.7
11.	PMOH	1.2	0.0	0.0	0.0	0.0	0.0	1.2
12.	LR pm (MW)	26.0	0.0	0.0	0.0	0.0	0.0	26.0
13.	NSC (MW)	161.0	161.0	161.0	161.0	161.0	161.0	161.0
14.	Oper MBtu	1048591	1178882	788134	1177990	1165018	875455	6234070
15.	Net Gen (MWH)	103185	114787	77397	115257	114945	85742	611313
16.	ANOHR (Btu/KWH)	10162	10270	10183	10221	10135	10210	10198
17.	NOF %	89.1	95.8	95.4	96.2	96.0	93.8	94.4
18.	NPC (MW)	161.0	161.0	161.0	161.0	161.0	161.0	161.0
19.	ANOHR Equation	10^6 / AKW * [69.20 + 18.16 * JAN + 12.44 * FEB + 15.12 * MAR - 8.67 * MAY + 10.92 * JUL] + 9,744						

Issued by: T. J. Bowden

Filed: April 1, 1999
Suspended:
Effective: April 1, 1999
Docket No.: 990001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	SMITH 2	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	0.0	21.5	97.8	93.4	99.8	100.0	68.8
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	0.0	184.9	707.2	737.7	744.0	720.0	3093.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	719.0	559.1	12.8	6.3	0.0	0.0	1297.2
6.	POH	719.0	331.5	0.0	0.0	0.0	0.0	1050.5
7.	FOH	0.0	227.6	12.8	6.3	0.0	0.0	246.7
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	0.0	51.1	6.5	94.5	9.9	0.0	162.0
10.	LR pf (MW)	0.0	92.8	14.1	86.1	21.8	0.0	81.4
11.	PMOH	0.0	0.0	8.3	0.0	0.0	0.0	8.3
12.	LR pm (MW)	0.0	0.0	60.0	0.0	0.0	0.0	60.0
13.	NSC (MW)	191.0	191.0	191.0	191.0	191.0	191.0	191.0
14.	Oper MBtu	105	270373	1316452	1293595	1379711	1307649	5567885
15.	Net Gen (MWH)	0	25830	131525	129034	137943	131676	556008
16.	ANOHR (Btu/KWH)	0	10467	10009	10025	10002	9931	10014
17.	NOF %	0.0	73.1	97.4	91.6	97.1	95.8	94.1
18.	NPC (MW)	191.0	191.0	191.0	191.0	191.0	191.0	191.0
19.	ANOHR Equation	10^6 / AKW * [-18.22 + 16.52 * MAR - 13.41 * MAY - 22.58 * SEP - 13.92 * NOV] + 10,446						

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Docket No.: 990001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	DANIEL 1	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	85.2	98.0	95.5	83.4	97.7	34.0	82.5
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	626.8	744.0	720.0	668.5	744.0	261.5	3764.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	92.2	0.0	0.0	75.5	0.0	458.5	626.2
6.	POH	0.0	0.0	0.0	0.0	0.0	458.5	458.5
7.	FOH	92.2	0.0	0.0	3.4	0.0	0.0	95.6
8.	MOH	0.0	0.0	0.0	72.1	0.0	0.0	72.1
9.	PFOH	155.2	138.9	470.4	482.7	202.8	230.7	1680.7
10.	LR pf (MW)	44.0	50.9	32.6	47.2	40.0	35.0	40.6
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
14.	Oper MBtu	2581545	3144341	3014237	2761421	3261113	1190020	15952677
15.	Net Gen (MWH)	247583	303498	285918	263368	312346	114365	1527078
16.	ANOHR (Btu/KWH)	10427	10360	10542	10485	10441	10405	10447
17.	NOF %	82.8	85.5	83.3	82.6	88.0	91.7	85.0
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0

19.	ANOHR Equation	10^6 / AKW * [-103.81 - 44.15 * MAR - 40.19 * NOV] + 12,196 - 0.00343 * LSRF / AKW

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Docket No.: 990001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: April 1998 - September 1998

	DANIEL 2	Apr '98	May '98	Jun '98	Jul '98	Aug '98	Sep '98	Total
1.	EAF (%)	65.8	88.6	79.6	91.5	78.6	72.7	79.6
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	498.7	723.0	636.5	744.0	645.9	589.5	3837.6
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	220.3	21.0	83.5	0.0	98.1	130.5	553.4
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7.	FOH	0.0	0.0	0.0	0.0	98.1	130.5	228.6
8.	MOH	220.3	21.0	83.5	0.0	0.0	0.0	324.8
9.	PFOH	208.0	639.0	630.8	587.6	592.7	497.0	3155.1
10.	LR pf (MW)	58.7	47.7	47.7	51.1	49.0	63.7	51.8
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
14.	Oper MBtu	2082081	3075589	2787431	3270805	2799693	2454414	16470013
15.	Net Gen (MWH)	204942	301482	268711	310738	265423	233899	1585195
16.	ANOHR (Btu/KWH)	10159	10202	10373	10526	10548	10493	10390
17.	NOF %	86.2	87.4	88.5	87.6	86.1	83.2	86.6
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0

19.	ANOHR Equation	10^6 / AKW * [218.47 + 30.22 * MAY + 42.12 * SEP] + 9,738

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Order No.:

Planned Outage Schedules (Actual)

Period of: April 1998 - September 1998

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Florida Public Service Commission
Docket No. 990001-EI
Gulf Power Company
Witness: G. D. Fontaine
Exhibit No. ___ (GDF-2)

EXHIBIT II TO THE TESTIMONY OF

G. D. FONTAINE

IN FPSC DOCKET 990001-EI

I. CORRECTIONS TO REPORTED DATA FOR THE OCTOBER 1998 - DECEMBER 1998 PERIOD

Additions and Corrections to Outages Previously Reported
for the October 1998 - December 1998 Period

Date	Unit	Change	Outage Type	Hours	MWH	Description
			None			

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for October 1998 - December 1998

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	1	10/17/98 - 10/25/98	217.0	10/30/98 - 11/07/98	193.6
Crist 7	2	10/31/98 - 11/08/98	216.0	10/16/98 - 10/25/98	206.7
Smith 2	3	12/12/98 - 12/20/98	216.0	12/12/98 - 12/19/98	170.6
Daniel 1	4	09/12/98 - 12/13/98	1777.0	09/11/98 - 12/21/98	1950.2
Daniel 2	5	10/10/98 - 10/18/98	216.0	11/07/98 - 11/30/98	555.3

* Planned outage hours in the October 1998 - December 1998 period only.

Notes:

1. This outage was swapped with Crist Unit 7 and proceeded as scheduled.
2. This outage was swapped with Crist Unit 6 and proceeded as scheduled.
3. This outage proceeded as scheduled and was completed quicker than forecasted.
4. This outage proceeded as scheduled and was extended due to work taking longer to complete than expected.
5. This outage was lenghtened to include stack repairs and moved to accommodate system reserve requirements.

Calculation of Actual Equivalent Availability
for October 1998 - December 1998
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Oct	Nov	Dec	Total
FOH	0.0	106.7	0.0	106.7
EFOH	28.2	14.5	19.4	62.1
MOH	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	0.0
PH	745.0	720.0	744.0	2209.0
POH	206.7	0.0	0.0	206.7
RSH	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(106.7 + 62.1 + 0.0 + 0.0)}{(2209.0 - 206.7 - 0.0)}$$

$$EUOR = 0.0843$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(216.0 + 0.0843\ (2209.0 - 216.0 - 0.0))}{2209.0} \right] \times 100 = 82.6\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for October 1998 - December 1998
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Oct	Nov	Dec	Total
FOH	0.0	24.3	26.7	51.0
EFOH	2.9	5.1	1.2	9.2
MOH	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	0.0
PH	745.0	720.0	744.0	2209.0
POH	0.0	0.0	0.0	0.0
RSH	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(51.0 + 9.2 + 0.0 + 0.0)}{(2209.0 - 0.0 - 0.0)}$$

$$EUOR = 0.0273$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 0.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(0.0 + 0.0273\ (2209.0 - 0.0 - 0.0))}{2209.0} \right] \times 100 = 97.3\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for October 1998 - December 1998
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Oct	Nov	Dec	Total
FOH	0.0	0.0	29.1	29.1
EFOH	1.9	0.1	0.1	2.1
MOH	0.0	0.0	3.7	3.7
EMOH	0.0	0.0	0.0	0.0
PH	745.0	720.0	744.0	2209.0
POH	0.0	0.0	170.6	170.6
RSH	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(29.1 + 2.1 + 3.7 + 0.0)}{(2209.0 - 170.6 - 0.0)}$$

$$EUOR = 0.0171$$

$$2.\ EA = \left[\ 1 - \frac{(\ POH^* + EUOR\ (PH - POH^* - RSH^*)\ )}{PH}\ \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[\ 1 - \frac{(216.0 + 0.0171\ (2209.0 - 216.0 - 0.0)\ )}{2209.0}\ \right] \times 100 = 88.7\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for October 1998 - December 1998
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Oct	Nov	Dec	Total
FOH	0.0	0.0	0.0	0.0
EFOH	0.0	0.0	3.9	3.9
MOH	0.0	0.0	225.5	225.5
EMOH	0.0	0.0	0.0	0.0
PH	745.0	720.0	744.0	2209.0
POH	745.0	720.0	485.2	1950.2
RSH	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(0.0 + 3.9 + 225.5 + 0.0)}{(2209.0 - 1950.2 - 0.0)}$$

$$EUOR = 0.8864$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1777.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1777.0 + 0.8864\ (2209.0 - 1777.0 - 0.0))}{2209.0} \right] \times 100 = 2.2\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for October 1998 - December 1998
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Oct	Nov	Dec	Total
FOH	145.3	0.0	23.7	169.0
EFOH	90.0	35.5	170.9	296.4
MOH	0.0	0.0	38.0	38.0
EMOH	4.2	0.0	0.0	4.2
PH	745.0	720.0	744.0	2209.0
POH	0.0	555.3	0.0	555.3
RSH	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(169.0 + 296.4 + 38.0 + 4.2)}{(2209.0 - 555.3 - 0.0)}$$

$$EUOR = 0.3069$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(216.0 + 0.3069\ (2209.0 - 216.0 - 0.0))}{2209.0} \right] \times 100 = 62.5\ \%$$

Note: Please refer to page 10 of this schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for October 1998 - December 1998

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 6	85.9	87.6	87.2	10.00
Crist 7	76.8	82.6	80.8	10.00
Smith 1	98.1	97.3	97.3	-10.00
Smith 2	87.1	88.7	88.0	10.00
Daniel 1	17.3	2.2	16.3	-10.00
Daniel 2	83.1	62.5	79.9	-10.00

* As appropriate from page 5, Schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Refer to pages 3 through 8 of this schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Crist 6

	Oct	Nov	Dec	Total
Pounds Coal(000's)	137814.8	112813.8	133194.0	383822.6
BTU/Lb*	11763.2	11815.7	11665.6	11744.8
Coal, MMBTU	1621143.1	1332974.0	1553787.9	4507905.0
Oil, MMBTU	1028.7	1375.7	1689.8	4094.2
Gas, MMBTU	500.0	3650.0	0.0	4150.0
Startup, MMBTU **	0.0	-4040.0	0.0	-4040.0
Total Fuel Consumption, MMBTU	1622671.8	1333959.7	1555477.7	4512109.2
Net MWH Generation***	148447	125595	146354	420396
Average Net Operating Heat Rate	10931	10621	10628	10733

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Crist 7

	Oct	Nov	Dec	Total
Pounds Coal(000's)	182145.4	212149.3	253251.9	647546.6
BTU/Lb*	11728.8	11694.6	11704.3	11708.0
Coal, MMBTU	2136347.0	2481001.2	2964136.2	7581484.4
Oil, MMBTU	498.3	1235.7	1339.0	3073.0
Gas, MMBTU	3470.0	7137.0	7686.0	18293.0
Startup, MMBTU **	-2256.0	-4512.0	0.0	-6768.0
Total Fuel Consumption, MMBTU	2138059.3	2484861.9	2973161.2	7596082.4
Net MWH Generation***	206383	243105	293705	743193
Average Net Operating Heat Rate	10360	10221	10123	10221

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Smith 1

	Oct	Nov	Dec	Total
Pounds Coal(000's)	97150.6	85394.9	86306.0	268851.5
BTU/Lb*	11857.3	11767.9	11811.3	11814.1
Coal, MMBTU	1151943.8	1004918.6	1019386.1	3176248.5
Oil, MMBTU	482.8	1681.6	1491.7	3656.1
Gas, MMBTU	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-964.0	-964.0	-1928.0
Total Fuel Consumption, MMBTU	1152426.6	1005636.2	1019913.8	3177976.6
Net MWH Generation***	113422	100881	101250	315553
Average Net Operating Heat Rate	10161	9969	10073	10071

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Smith 2

	Oct	Nov	Dec	Total
Pounds Coal(000's)	113681.2	111864.2	79553.5	305098.9
BTU/Lb*	11793.5	11752.9	11734.3	11763.2
Coal, MMBTU	1340699.2	1314728.8	933504.6	3588932.6
Oil, MMBTU	232.2	216.9	2332.8	2781.9
Gas, MMBTU	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-1190.0	-1190.0
Total Fuel Consumption, MMBTU	1340931.4	1314945.7	934647.4	3590524.5
Net MWH Generation***	135252	132201	93443	360896
Average Net Operating Heat Rate	9914	9947	10002	9949

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Daniel 1

	Oct	Nov	Dec	Total
Pounds Coal(000's)	0.0	0.0	4652.1	4652.1
BTU/Lb*	0.0	0.0	9223.4	9223.4
Coal, MMBTU	0.0	0.0	42908.2	42908.2
Oil, MMBTU	0.0	0.0	7522.9	7522.9
Gas, MMBTU	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-2388.7	-2388.7
Total Fuel Consumption, MMBTU	0.0	0.0	48042.4	48042.4
Net MWH Generation***	0	0	3297	3297
Average Net Operating Heat Rate	--	--	14572	14572

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for October 1998 - December 1998

Daniel 2

	Oct	Nov	Dec	Total
Pounds Coal(000's)	245598.3	59765.5	251742.6	557106.4
BTU/Lb*	9191.0	9337.9	9207.3	9214.1
Coal, MMBTU	2257294.0	558084.3	2317869.6	5133247.9
Oil, MMBTU	11167.4	3848.9	5483.4	20499.7
Gas, MMBTU	0.0	0.0	0.0	0.0
Startup, MMBTU **	-9554.8	-2388.7	-2388.7	-14332.2
Total Fuel Consumption, MMBTU	2258906.6	559544.5	2320964.3	5139415.4
Net MWH Generation***	215074	52914	222012	490000
Average Net Operating Heat Rate	10503	10575	10454	10489

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for October 1998 - December 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed June 22, 1998

Crist 6

		Oct	Nov	Dec	Oct - Dec
1.	Target Heat Rate*	10466	10797	10930	
2.	Target Heat Rate at Actual Conditions**	10448	10639	10696	
3.	Adjustment to Actual Heat Rate (1-2)	18	158	234	
4.	Actual Heat Rate (Page 2 of Sched. 3)	10931	10621	10628	
5.	Adjusted Actual Heat Rate (4+3)	10949	10779	10862	
6.	Net MWH Generation	148447	125595	146354	
7.	Adjusted Actual Heat Rate for October 1998 - December 1998 $=(\Sigma(5*6)/\Sigma 6)$				10868

* From page 18, schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for October 1998 - December 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed June 22, 1998

Crist 7

		Oct	Nov	Dec	Oct - Dec
1.	Target Heat Rate*	10114	10135	10216	
2.	Target Heat Rate at Actual Conditions**	10258	10232	10235	
3.	Adjustment to Actual Heat Rate (1-2)	-144	-97	-19	
4.	Actual Heat Rate (Page 3 of Sched. 3)	10360	10221	10123	
5.	Adjusted Actual Heat Rate (4+3)	10216	10124	10104	
6.	Net MWH Generation	206383	243105	293705	
7.	Adjusted Actual Heat Rate for October 1998 - December 1998 $=(\Sigma(5*6)/\Sigma 6)$				10142

* From page 19, schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for October 1998 - December 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed June 22, 1998

Smith 1

		Oct	Nov	Dec	Oct - Dec
1.	Target Heat Rate*	10186	10196	10242	
2.	Target Heat Rate at Actual Conditions**	10198	10219	10232	
3.	Adjustment to Actual Heat Rate (1-2)	-12	-23	10	
4.	Actual Heat Rate (Page 4 of Sched. 3)	10161	9969	10073	
5.	Adjusted Actual Heat Rate (4+3)	10149	9946	10083	
6.	Net MWH Generation	113422	100881	101250	
7.	Adjusted Actual Heat Rate for October 1998 - December 1998 $=(\Sigma(5*6)/\Sigma 6)$				10063

* From page 20, schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Calculation of Average Net Operating Heat Rate
for October 1998 - December 1998
Adjusted to Target Basis Using Heat Rate
Equations Filed June 22, 1998

Daniel 1

		Oct	Nov	Dec	Oct - Dec
1.	Target Heat Rate*	-	-	10655	
2.	Target Heat Rate at Actual Conditions**	-	-	10550	
3.	Adjustment to Actual Heat Rate (1-2)	0	0	105	
4.	Actual Heat Rate (Page 6 of Sched. 3)	0	0	14571	
5.	Adjusted Actual Heat Rate (4+3)	0	0	14676	
6.	Net MWH Generation	0	0	3297	
7.	Adjusted Actual Heat Rate for October 1998 - December 1998 $=(\Sigma(5*6)/\Sigma 6)$				14676

* From page 22, schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 15 of this schedule.

Actual Values of
Target Heat Rate Equation Parameters
for October 1998 - December 1998

	Oct	Nov	Dec
Crist 6			
AKW * 10^{+3}	206.5	228.1	196.7
LSRF * 10^{+6}	47250.6	57334.5	43301.9
Crist 7			
AKW * 10^{+3}	383.4	396.4	394.8
LSRF * 10^{+6}	158188.1	170204.8	169943.8
Smith 1			
AKW * 10^{+3}	152.2	145.0	141.2
LSRF * 10^{+6}	23376.0	21511.6	20628.2
Smith 2			
AKW * 10^{+3}	181.5	183.6	172.9
LSRF • 10^{+6}	33201.9	33786.6	30572.2
Daniel 1			
AKW * 10^{+3}	0.0	0.0	99.0
LSRF * 10^{+6}	0.0	0.0	14196.3
Daniel 2			
AKW * 10^{+3}	358.6	321.3	325.4
LSRF * 10^{+6}	137327.3	112432.0	109565.0

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [425.50 - 38.13 * FEB - 32.39 * MAR - 43.76 * OCT]
+ 6,831 + 0.00773 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [306.05 + 76.91 * MAY + 35.39 * JUN + 95.55 * JUL + 47.29 * AUG]
+ 9,460

Smith 1 ANOHR = 10^6 / AKW * [66.60 + 13.44 * JAN + 16.58 * FEB + 11.46 * MAR - 8.41 * MAY + 11.13 * JUL]
+ 9,760

Smith 2 ANOHR = 10^6 / AKW * [159.06 + 14.06 * JAN + 42.51 * MAR + 24.16 * JUL + 20.05 * AUG]
+ 6,911 + 0.01352 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [-141.87 - 50.17 * MAR]
+ 12,568 - 0.00408 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [4.25 - 61.50 * JAN - 54.19 * FEB - 46.22 * MAR - 38.23 * OCT]
+ 11,573 - 0.00296 * LSRF / AKW

Where:		
	ANOHR	Average Net Operating Heat Rate, BTU/KWH
	AKW	Average Kilowatt Load, KW
	LSRF	Load Square Range Factor, KW^2
	JAN	January, 0 if not January, 1 if January
	FEB	February, 0 if not February, 1 if February
	MAR	March, 0 if not March, 1 if March
	APR	April, 0 if not April, 1 if April
	MAY	May, 0 if not May, 1 if May
	JUN	June, 0 if not June, 1 if June
	JUL	July, 0 if not July, 1 if July
	AUG	August, 0 if not August, 1 if August
	SEP	September, 0 if not September, 1 if September
	OCT	October, 0 if not October, 1 if October
	NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for October 1998 - December 1998

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 6	10737	10868	10415	-2.27
Crist 7	10156	10142	9851	0.00
Smith 1	10207	10063	9901	2.99
Smith 2	10246	9942	9939	9.87
Daniel 1	10655	14676	10335	-10.00
Daniel 2	10300	10299	9991	0.00

* From page 5, Schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

** Refer to pages 8 through 13 of this schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

$$\text{If } [\,(2)-(3)-75\,] > 0 \text{ then points} = \frac{(2)-(3)-75}{(2)-(4)-75} \bullet 10$$

$$\text{If } [\,(2)-(3)+75\,] < 0 \text{ then points} = \frac{(2)-(3)+75}{(2)-(4)-75} * 10$$

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for October 1998 - December 1998

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 6	10.00	0.008	-2.27	0.113
Crist 7	10.00	0.118	0.00	0.247
Smith 1	-10.00	0.019	2.99	0.059
Smith 2	10.00	0.032	9.87	0.055
Daniel 1	-10.00	0.018	-10.00	0.042
Daniel 2	-10.00	0.034	0.00	0.255

Company GPIF Points = + 10.00 * 0.008 - 2.27 * 0.113
+ 10.00 * 0.118 + 0.00 * 0.247
- 10.00 * 0.019 + 2.99 * 0.059
+ 10.00 * 0.032 + 9.87 * 0.055
- 10.00 * 0.018 - 10.00 * 0.042
- 10.00 * 0.034 + 0.00 * 0.255
0.91

Company reward/penalty = 0.91 points * $42501 per point
= $38,676

* From page 5, Schedule 3 of Exhibit to G. D. Fontaine's June 22, 1998 GPIF testimony in Docket 980001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE OCTOBER 1998 - DECEMBER 1998 PERIOD

Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: October 1998 - December 1998

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	1344	425
+ 9	1210	383
+ 8	1075	340
+ 7	941	298
+ 6	806	255
+ 5	672	213
+ 4	538	170
+ 3	403	128
+ 2	269	85
+ 1	134	43
0	0	0
- 1	-152	-43
- 2	-304	-85
- 3	-456	-128
- 4	-608	-170
- 5	-760	-213
- 6	-912	-255
- 7	-1064	-298
- 8	-1216	-340
- 9	-1368	-383
- 10	-1520	-425
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: October 1998 - December 1998

Line 1	Beginning of Period Balance of Common Equity	$432,725,103
	End of Month Balance of Common Equity:	
Line 2	Month of Oct '98	$420,345,891
Line 3	Month of Nov '98	$422,966,199
Line 4	Month of Dec '98	$427,652,271
Line 5	Average Common Equity for the Period (sum of line 1 through line 4 divided by 4)	$425,922,366
Line 6	25 Basis Points	0.0025
Line 7	Revenue Expansion Factor	60.4524%
Line 8	Maximum Allowed Incentive Dollars (line 5 multiplied by line 6 divided by line 7 multiplied by 0.25)	$440,349
Line 9	Jurisdictional Sales (KWH)	2,064,403,827
Line 10	Total Territorial Sales (KWH)	2,138,911,706
Line 11	Jurisdictional Separation Factor (line 9 divided by line 10)	96.5166%
Line 12	Maximum Allowed Jurisdictional Incentive Dollars (line 8 multiplied by line 11)	$425,010

Issued by: T. J. Bowden

Filed: April 1,1999
Suspended:
Effective: April 1,1999
Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	11	87.20	+ 10	152	10,415
+ 9	10	87.07	+ 9	137	10,440
+ 8	9	86.94	+ 8	122	10,464
+ 7	8	86.81	+ 7	106	10,489
+ 6	7	86.68	+ 6	91	10,514
+ 5	6	86.55	+ 5	76	10,539
+ 4	4	86.42	+ 4	61	10,563
+ 3	3	86.29	+ 3	46	10,588
+ 2	2	86.16	+ 2	30	10,613
+ 1	1	86.03	+ 1	15	10,637
				0	10,662
0	0	85.90	0	0	10,737
				0	10,812
- 1	(8)	85.71	- 1	(15)	10,837
- 2	(16)	85.52	- 2	(30)	10,861
- 3	(24)	85.33	- 3	(46)	10,886
- 4	(32)	85.14	- 4	(61)	10,911
- 5	(40)	84.95	- 5	(76)	10,936
- 6	(47)	84.76	- 6	(91)	10,960
- 7	(55)	84.57	- 7	(106)	10,985
- 8	(63)	84.38	- 8	(122)	11,010
- 9	(71)	84.19	- 9	(137)	11,034
- 10	(79)	84.00	- 10	(152)	11,059
Weighting Factor:		0.008	Weighting Factor:		0.113

Issued by: T. J. Bowden

Filed: April 1,1999
Suspended:
Effective: April 1,1999
Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	158	80.80	+ 10	332	9,851
+ 9	142	80.40	+ 9	299	9,874
+ 8	126	80.00	+ 8	266	9,897
+ 7	111	79.60	+ 7	232	9,920
+ 6	95	79.20	+ 6	199	9,943
+ 5	79	78.80	+ 5	166	9,966
+ 4	63	78.40	+ 4	133	9,989
+ 3	47	78.00	+ 3	100	10,012
+ 2	32	77.60	+ 2	66	10,035
+ 1	16	77.20	+ 1	33	10,058
				0	10,081
0	0	76.80	0	0	10,156
				0	10,231
- 1	(20)	76.20	- 1	(33)	10,254
- 2	(40)	75.60	- 2	(66)	10,277
- 3	(60)	75.00	- 3	(100)	10,300
- 4	(80)	74.40	- 4	(133)	10,323
- 5	(100)	73.80	- 5	(166)	10,346
- 6	(119)	73.20	- 6	(199)	10,369
- 7	(139)	72.60	- 7	(232)	10,392
- 8	(159)	72.00	- 8	(266)	10,415
- 9	(179)	71.40	- 9	(299)	10,438
- 10	(199)	70.80	- 10	(332)	10,461
Weighting Factor:		0.118	Weighting Factor:		0.247

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Suspended:
Effective: April 1,1999
Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	25	98.70	+ 10	79	9,901
+ 9	23	98.64	+ 9	71	9,924
+ 8	20	98.58	+ 8	63	9,947
+ 7	18	98.52	+ 7	55	9,970
+ 6	15	98.46	+ 6	47	9,993
+ 5	13	98.40	+ 5	40	10,017
+ 4	10	98.34	+ 4	32	10,040
+ 3	8	98.28	+ 3	24	10,063
+ 2	5	98.22	+ 2	16	10,086
+ 1	3	98.16	+ 1	8	10,109
				0	10,132
0	0	98.10	0	0	10,207
				0	10,282
- 1	(3)	98.02	- 1	(8)	10,305
- 2	(7)	97.94	- 2	(16)	10,328
- 3	(10)	97.86	- 3	(24)	10,351
- 4	(14)	97.78	- 4	(32)	10,374
- 5	(17)	97.70	- 5	(40)	10,398
- 6	(20)	97.62	- 6	(47)	10,421
- 7	(24)	97.54	- 7	(55)	10,444
- 8	(27)	97.46	- 8	(63)	10,467
- 9	(31)	97.38	- 9	(71)	10,490
- 10	(34)	97.30	- 10	(79)	10,513
Weighting Factor:		0.019	Weighting Factor:		0.059

Issued by: T. J. Bowden

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	43	88.00	+ 10	74	9,939
+ 9	39	87.91	+ 9	67	9,962
+ 8	34	87.82	+ 8	59	9,985
+ 7	30	87.73	+ 7	52	10,009
+ 6	26	87.64	+ 6	44	10,032
+ 5	22	87.55	+ 5	37	10,055
+ 4	17	87.46	+ 4	30	10,078
+ 3	13	87.37	+ 3	22	10,101
+ 2	9	87.28	+ 2	15	10,125
+ 1	4	87.19	+ 1	7	10,148
				0	10,171
0	0	87.10	0	0	10,246
				0	10,321
- 1	(7)	86.96	- 1	(7)	10,344
- 2	(13)	86.82	- 2	(15)	10,367
- 3	(20)	86.68	- 3	(22)	10,391
- 4	(26)	86.54	- 4	(30)	10,414
- 5	(33)	86.40	- 5	(37)	10,437
- 6	(40)	86.26	- 6	(44)	10,460
- 7	(46)	86.12	- 7	(52)	10,483
- 8	(53)	85.98	- 8	(59)	10,507
- 9	(59)	85.84	- 9	(67)	10,530
- 10	(66)	85.70	- 10	(74)	10,553
Weighting Factor:		0.032	Weighting Factor:		0.055

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	24	18.00	+ 10	57	10,335
+ 9	22	17.93	+ 9	51	10,360
+ 8	19	17.86	+ 8	46	10,384
+ 7	17	17.79	+ 7	40	10,409
+ 6	14	17.72	+ 6	34	10,433
+ 5	12	17.65	+ 5	29	10,458
+ 4	10	17.58	+ 4	23	10,482
+ 3	7	17.51	+ 3	17	10,507
+ 2	5	17.44	+ 2	11	10,531
+ 1	2	17.37	+ 1	6	10,556
				0	10,580
0	0	17.30	0	0	10,655
				0	10,730
- 1	(2)	17.20	- 1	(6)	10,755
- 2	(3)	17.10	- 2	(11)	10,779
- 3	(5)	17.00	- 3	(17)	10,804
- 4	(6)	16.90	- 4	(23)	10,828
- 5	(8)	16.80	- 5	(29)	10,853
- 6	(9)	16.70	- 6	(34)	10,877
- 7	(11)	16.60	- 7	(40)	10,902
- 8	(12)	16.50	- 8	(46)	10,926
- 9	(14)	16.40	- 9	(51)	10,951
- 10	(15)	16.30	- 10	(57)	10,975
Weighting Factor:		0.018	Weighting Factor:		0.042

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: October 1998 - December 1998

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	46	85.20	+ 10	343	9,991
+ 9	41	84.99	+ 9	309	10,014
+ 8	37	84.78	+ 8	274	10,038
+ 7	32	84.57	+ 7	240	10,061
+ 6	28	84.36	+ 6	206	10,085
+ 5	23	84.15	+ 5	172	10,108
+ 4	18	83.94	+ 4	137	10,131
+ 3	14	83.73	+ 3	103	10,155
+ 2	9	83.52	+ 2	69	10,178
+ 1	5	83.31	+ 1	34	10,202
				0	10,225
0	0	83.10	0	0	10,300
				0	10,375
- 1	(9)	82.78	- 1	(34)	10,398
- 2	(18)	82.46	- 2	(69)	10,422
- 3	(27)	82.14	- 3	(103)	10,445
- 4	(36)	81.82	- 4	(137)	10,469
- 5	(45)	81.50	- 5	(172)	10,492
- 6	(54)	81.18	- 6	(206)	10,515
- 7	(63)	80.86	- 7	(240)	10,539
- 8	(72)	80.54	- 8	(274)	10,562
- 9	(81)	80.22	- 9	(309)	10,586
- 10	(90)	79.90	- 10	(343)	10,609
Weighting Factor:		0.034	Weighting Factor:		0.255

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Order No.:

GPIF Unit Performance Summary

Gulf Power Company

Period of: October 1998 - December 1998

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 6	0.8	85.9	87.2	84.0	11	-79	87.6	$11
Crist 7	11.8	76.8	80.8	70.8	158	-199	82.6	$158
Smith 1	1.9	98.1	98.7	97.3	25	-34	97.3	($34)
Smith 2	3.2	87.1	88.0	85.7	43	-66	88.7	$43
Daniel 1	1.8	17.3	18.0	16.3	24	-15	2.2	($15)
Daniel 2	3.4	83.1	85.2	79.9	46	-90	62.5	($90)
Total:	22.9							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 6	11.3	10,737	58.4	11,059	10,415	$152	($152)	10,868	($35)
Crist 7	24.7	10,156	87.3	10,461	9,851	$332	($332)	10,142	$0
Smith 1	5.9	10,207	92.6	10,513	9,901	$79	($79)	10,063	$24
Smith 2	5.5	10,246	90.9	10,553	9,939	$74	($74)	9,942	$73
Daniel 1	4.2	10,655	65.1	10,975	10,335	$57	($57)	14,676	($57)
Daniel 2	25.5	10,300	84.4	10,609	9,991	$343	($343)	10,299	$0
Total:	77.1								

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Order No.:

Actual Unit Performance Data

Gulf Power Company

Period of: October 1998 - December 1998

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 6	88.6	-1.0	87.6
Crist 7	83.0	-0.4	82.6
Smith 1	97.3	0.0	97.3
Smith 2	90.7	-2.0	88.7
Daniel 1	1.3	0.9	2.2
Daniel 2	51.9	10.6	62.5

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 6	10,733	135	10,868
Crist 7	10,221	-79	10,142
Smith 1	10,071	-8	10,063
Smith 2	9,949	-7	9,942
Daniel 1	14,571	105	14,676
Daniel 2	10,489	-190	10,299

* Refer to pages 3 through 8, Schedule 2.

** Refer to pages 8 through 13, Schedule 3.

Issued by: T. J. Bowden

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: October 1998 - December 1998

	CRIST 7	Oct '98	Nov '98	Dec '98				Total
1.	EAF (%)	68.5	83.2	97.4				83.0
2.	PH	745.0	720.0	744.0				2209.0
3.	SH	538.3	613.3	744.0				1895.6
4.	RSH	0.0	0.0	0.0				0.0
5.	UH	206.7	106.7	0.0				313.4
6.	POH	206.7	0.0	0.0				206.7
7.	FOH	0.0	106.7	0.0				106.7
8.	MOH	0.0	0.0	0.0				0.0
9.	PFOH	286.0	93.9	61.2				441.1
10.	LR pf (MW)	49.7	77.9	159.6				71.0
11.	PMOH	0.0	0.0	0.0				0.0
12.	LR pm (MW)	0.0	0.0	0.0				0.0
13.	NSC (MW)	504.0	504.0	504.0				504.0
14.	Oper MBtu	2138059	2484862	2973161				7596082
15.	Net Gen (MWH)	206383	243105	293705				743193
16.	ANOHR (Btu/KWH)	10360	10221	10123				10221
17.	NOF %	76.1	78.6	78.3				77.8
18.	NPC (MW)	504.0	504.0	504.0				504.0
19.	ANOHR Equation	10^6 / AKW * [306.05 + 76.91 * MAY + 35.39 * JUN + 95.55 * JUL + 47.29 * AUG] + 9,460						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: October 1998 - December 1998

	SMITH 1	Oct '98	Nov '98	Dec '98				Total
1.	EAF (%)	99.6	95.9	96.3				97.3
2.	PH	745.0	720.0	744.0				2209.0
3.	SH	745.0	695.7	717.3				2158.0
4.	RSH	0.0	0.0	0.0				0.0
5.	UH	0.0	24.3	26.7				51.0
6.	POH	0.0	0.0	0.0				0.0
7.	FOH	0.0	24.3	26.7				51.0
8.	MOH	0.0	0.0	0.0				0.0
9.	PFOH	9.4	28.1	6.4				43.9
10.	LR pf (MW)	50.1	29.1	29.5				33.7
11.	PMOH	0.0	0.0	0.0				0.0
12.	LR pm (MW)	0.0	0.0	0.0				0.0
13.	NSC (MW)	161.0	161.0	161.0				161.0
14.	Oper MBtu	1152427	1005636	1019914				3177977
15.	Net Gen (MWH)	113422	100881	101250				315553
16.	ANOHR (Btu/KWH)	10161	9969	10073				10071
17.	NOF %	94.6	90.1	87.7				90.8
18.	NPC (MW)	161.0	161.0	161.0				161.0
19.	ANOHR Equation	10^6 / AKW * [66.60 + 13.44 * JAN + 16.58 * FEB + 11.46 * MAR - 8.41 * MAY + 11.13 * JUL] + 9,760						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: October 1998 - December 1998

	SMITH 2	Oct '98	Nov '98	Dec '98				Total
1.	EAF (%)	99.7	100.0	72.6				90.7
2.	PH	745.0	720.0	744.0				2209.0
3.	SH	745.0	720.0	540.6				2005.6
4.	RSH	0.0	0.0	0.0				0.0
5.	UH	0.0	0.0	203.4				203.4
6.	POH	0.0	0.0	170.6				170.6
7.	FOH	0.0	0.0	29.1				29.1
8.	MOH	0.0	0.0	3.7				3.7
9.	PFOH	11.9	2.5	4.8				19.2
10.	LR pf (MW)	30.8	6.0	5.4				21.2
11.	PMOH	0.0	0.0	0.0				0.0
12.	LR pm (MW)	0.0	0.0	0.0				0.0
13.	NSC (MW)	191.0	191.0	191.0				191.0
14.	Oper MBtu	1340931	1314946	934647				3590524
15.	Net Gen (MWH)	135252	132201	93443				360896
16.	ANOHR (Btu/KWH)	9914	9947	10002				9949
17.	NOF %	95.1	96.1	90.5				94.2
18.	NPC (MW)	191.0	191.0	191.0				191.0
19.	ANOHR Equation	$10^6 / AKW * [159.06 + 14.06 * JAN + 42.51 * MAR + 24.16 * JUL + 20.05 * AUG] + 6{,}911 + 0.01352 * LSRF / AKW$						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: October 1998 - December 1998

	DANIEL 1	Oct '98	Nov '98	Dec '98				Total
1.	EAF (%)	0.0	0.0	4.0				1.3
2.	PH	745.0	720.0	744.0				2209.0
3.	SH	0.0	0.0	33.3				33.3
4.	RSH	0.0	0.0	0.0				0.0
5.	UH	745.0	720.0	710.7				2175.7
6.	POH	745.0	720.0	485.2				1950.2
7.	FOH	0.0	0.0	0.0				0.0
8.	MOH	0.0	0.0	225.5				225.5
9.	PFOH	0.0	0.0	8.5				8.5
10.	LR pf (MW)	0.0	0.0	219.4				219.4
11.	PMOH	0.0	0.0	0.0				0.0
12.	LR pm (MW)	0.0	0.0	0.0				0.0
13.	NSC (MW)	477.0	477.0	477.0				477.0
14.	Oper MBtu	0	0	48042				48042
15.	Net Gen (MWH)	0	0	3297				3297
16.	ANOHR (Btu/KWH)	0	0	14571				14571
17.	NOF %	0.0	0.0	20.8				20.8
18.	NPC (MW)	477.0	477.0	477.0				477.0
19.	ANOHR Equation	10^6 / AKW * [-141.87 - 50.17 * MAR] + 12,568 - 0.00408 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: October 1998 - December 1998

	DANIEL 2	Oct '98	Nov '98	Dec '98				Total
1.	EAF (%)	67.8	17.9	68.7				51.9
2.	PH	745.0	720.0	744.0				2209.0
3.	SH	599.7	164.7	682.3				1446.7
4.	RSH	0.0	0.0	0.0				0.0
5.	UH	145.3	555.3	61.7				762.3
6.	POH	0.0	555.3	0.0				555.3
7.	FOH	145.3	0.0	23.7				169.0
8.	MOH	0.0	0.0	38.0				38.0
9.	PFOH	505.0	105.6	640.9				1251.5
10.	LR pf (MW)	85.0	160.4	127.2				113.0
11.	PMOH	16.3	0.0	0.0				16.3
12.	LR pm (MW)	124.0	0.0	0.0				124.0
13.	NSC (MW)	477.0	477.0	477.0				477.0
14.	Oper MBtu	2258907	559544	2320964				5139415
15.	Net Gen (MWH)	215074	52914	222012				490000
16.	ANOHR (Btu/KWH)	10503	10575	10454				10489
17.	NOF %	75.2	67.4	68.2				71.0
18.	NPC (MW)	477.0	477.0	477.0				477.0

19.	ANOHR Equation	10^6 / AKW * [4.25 - 61.50 * JAN - 54.19 * FEB - 46.22 * MAR - 38.23 * OCT] + 11,573 - 0.00296 * LSRF / AKW

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Order No.:

Planned Outage Schedules (Actual)

Period of: October 1998 - December 1998

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 990001-EI

Before me the undersigned authority, personally appeared George D. Fontaine, who being first duly sworn, deposes, and says that he is the Performance Test Specialist for Gulf Power Company, a Maine Corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

George D. Fontaine
Performance Test Specialist

Sworn to and subscribed before me this 30 day of March, 1999.

Notary Public, State of Florida at Large

PEGGY A. WILSON
Notary Public-State of FL
Comm. Exp: Sept. 1, 2001
Comm. No: CC 676351

Florida Public Service Commission
Docket No. 990001-EI
Gulf Power Company
Witness: J. R. Douglass
Exhibit No. ___ (JRD-1)

EXHIBIT TO THE TESTIMONY OF

J. R. DOUGLASS

IN FPSC DOCKET 990001-EI

FLORIDA PUBLIC SERVICE COMMISSION
990001-EI EXHIBIT NO. 14
Douglass
DATE: 11-22-99

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY]

+ 10,287

Crist 7 ANOHR = 10^6 / AKW * [215.83 + 54.63 * MAY]

• 9,725

Smith 1 ANOHR = 10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV]

+ 5,563 + 0.01691 * LSRF / AKW

Smith 2 ANOHR = 10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP]

+ 9,526

Daniel 1 ANOHR = 10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN]

+ 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

Daniel 2 ANOHR = 10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP]

+ 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]

Where:

ANOHR =	Average Net Operating Heat Rate, BTU/KWH
AKW =	Average Kilowatt Load, KW
LSRF =	Load Square Range Factor, KW^2
BTU/LB =	Coal Burned Average Heat Content, BTU/LB
JAN =	January, 0 if not January, 1 if January
FEB =	February, 0 if not February, 1 if February
MAR =	March, 0 if not March, 1 if March
APR =	April, 0 if not April, 1 if April
MAY =	May, 0 if not May, 1 if May
JUN =	June, 0 if not June, 1 if June
JUL =	July, 0 if not July, 1 if July
AUG =	August, 0 if not August, 1 if August
SEP =	September, 0 if not September, 1 if September
OCT =	October, 0 if not October, 1 if October
NOV =	November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10554	168	166.0	32167	0	0	0	0	0	0	1	0	0	0	0	0	1996
10506	168	189.1	40435	0	0	0	0	0	0	1	0	0	0	0	0	1996
10437	168	208.4	48527	0	0	0	0	0	0	1	0	0	0	0	0	1996
10660	168	174.1	34747	0	0	0	0	0	0	1	0	0	0	0	0	1996
10594	168	179.8	37388	0	0	0	0	0	0	0	1	0	0	0	0	1996
10555	168	185.8	40687	0	0	0	0	0	0	0	1	0	0	0	0	1996
10635	168	177.1	36296	0	0	0	0	0	0	0	1	0	0	0	0	1996
10574	168	166.9	30468	0	0	0	0	0	0	0	1	0	0	0	0	1996
10800	168	143.3	23026	0	0	0	0	0	0	0	1	0	0	0	0	1996
10577	168	170.0	32930	0	0	0	0	0	0	0	0	1	0	0	0	1996
10559	168	164.6	32612	0	0	0	0	0	0	0	0	1	0	0	0	1996
10645	168	186.3	42682	0	0	0	0	0	0	0	0	1	0	0	0	1996
10544	168	185.4	41787	0	0	0	0	0	0	0	0	1	0	0	0	1996
10660	24	150.4	27195	0	0	0	0	0	0	0	0	1	0	0	0	1996
10934	168	137.4	20296	0	0	0	0	0	0	0	0	0	1	0	0	1996
10769	168	139.4	20831	0	0	0	0	0	0	0	0	0	1	0	0	1996
10484	168	156.3	27865	0	0	0	0	0	0	0	0	0	1	0	0	1996
10613	169	162.6	30049	0	0	0	0	0	0	0	0	0	1	0	0	1996
10882	168	141.1	21315	0	0	0	0	0	0	0	0	0	0	1	0	1996
11015	168	142.8	22265	0	0	0	0	0	0	0	0	0	0	1	0	1996
10666	168	171.6	32771	0	0	0	0	0	0	0	0	0	0	1	0	1996
10652	152	160.3	27575	0	0	0	0	0	0	0	0	0	0	1	0	1996
11712	20	145.9	23325	0	0	0	0	0	0	0	0	0	0	0	1	1996
10980	168	142.8	21954	0	0	0	0	0	0	0	0	0	0	0	0	1996
10660	160	169.5	33373	0	0	0	0	0	0	0	0	0	0	0	0	1996
11318	158	120.6	14901	0	0	0	0	0	0	0	0	0	0	0	0	1996
11191	168	125.7	17423	1	0	0	0	0	0	0	0	0	0	0	0	1997
10847	168	147.7	24075	1	0	0	0	0	0	0	0	0	0	0	0	1997
10676	168	167.5	31788	1	0	0	0	0	0	0	0	0	0	0	0	1997
10711	168	140.5	20753	1	0	0	0	0	0	0	0	0	0	0	0	1997
10626	133	177.7	36651	1	0	0	0	0	0	0	0	0	0	0	0	1997
12327	22	122.4	15294	0	1	0	0	0	0	0	0	0	0	0	1	1997
10918	93	144.1	22329	0	1	0	0	0	0	0	0	0	0	0	1	1997
10948	46	135.4	18587	0	0	1	0	0	0	0	0	0	0	0	0	1997
11479	26	123.3	15940	0	0	1	0	0	0	0	0	0	0	0	1	1997
11031	91	126.4	16459	0	0	1	0	0	0	0	0	0	0	0	0	1997
11614	25	124.6	16021	0	0	1	0	0	0	0	0	0	0	0	1	1997
10807	167	149.0	23780	0	0	0	1	0	0	0	0	0	0	0	0	1997
10694	168	148.4	23603	0	0	0	1	0	0	0	0	0	0	0	0	1997
10617	168	172.8	33320	0	0	0	1	0	0	0	0	0	0	0	0	1997
10511	168	202.4	46310	0	0	0	1	0	0	0	0	0	0	0	0	1997
10724	99	170.2	33466	0	0	0	0	1	0	0	0	0	0	0	0	1997
11029	141	149.7	27563	0	0	0	0	1	0	0	0	0	0	0	1	1997
10403	168	198.0	42852	0	0	0	0	1	0	0	0	0	0	0	0	1997
10866	168	157.9	32869	0	0	0	0	1	0	0	0	0	0	0	0	1997
10818	167	162.4	30606	0	0	0	0	1	0	0	0	0	0	0	0	1997
11330	168	133.0	20826	0	0	0	0	0	1	0	0	0	0	0	0	1997

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11102	168	174.3	35632	0	0	0	0	0	1	0	0	0	0	0	0	1997
10818	168	187.2	40880	0	0	0	0	0	1	0	0	0	0	0	0	1997
10943	168	179.6	37652	0	0	0	0	0	1	0	0	0	0	0	0	1997
10883	168	208.7	50498	0	0	0	0	0	0	1	0	0	0	0	0	1997
11483	168	155.8	27723	0	0	0	0	0	0	1	0	0	0	0	0	1997
11234	168	162.4	30227	0	0	0	0	0	0	1	0	0	0	0	0	1997
10901	168	213.4	50938	0	0	0	0	0	0	1	0	0	0	0	0	1997
10871	168	178.9	37117	0	0	0	0	0	0	0	1	0	0	0	0	1997
11006	168	173.3	34804	0	0	0	0	0	0	0	1	0	0	0	0	1997
10539	168	222.2	54505	0	0	0	0	0	0	0	1	0	0	0	0	1997
10554	168	208.3	49645	0	0	0	0	0	0	0	1	0	0	0	0	1997
10616	168	201.2	48706	0	0	0	0	0	0	0	1	0	0	0	0	1997
10560	168	212.0	52281	0	0	0	0	0	0	0	0	1	0	0	0	1997
10516	117	213.7	53660	0	0	0	0	0	0	0	0	1	0	0	1	1997
10373	165	228.3	58801	0	0	0	0	0	0	0	0	1	0	0	0	1997
10831	168	179.8	37447	0	0	0	0	0	0	0	0	1	0	0	0	1997
10574	18	195.0	45296	0	0	0	0	0	0	0	0	1	0	0	0	1997
10415	75	219.5	54886	0	0	0	0	0	0	0	0	0	1	0	1	1997
10684	168	202.9	46288	0	0	0	0	0	0	0	0	0	1	0	0	1997
10679	70	163.2	28695	0	0	0	0	0	0	0	0	0	1	0	0	1997
11436	110	165.1	32220	0	0	0	0	0	0	0	0	0	0	0	1	1997
10680	168	235.3	61294	0	0	0	0	0	0	0	0	0	0	0	0	1997
10914	76	198.9	45226	0	0	0	0	0	0	0	0	0	0	0	0	1997
11744	99	144.8	22986	0	0	0	0	0	0	0	0	0	0	0	1	1997
11279	15	123.8	16118	1	0	0	0	0	0	0	0	0	0	0	0	1998
10939	149	218.3	53383	1	0	0	0	0	0	0	0	0	0	0	1	1998
10810	168	234.2	59691	1	0	0	0	0	0	0	0	0	0	0	0	1998
11037	168	197.0	43142	1	0	0	0	0	0	0	0	0	0	0	0	1998
11229	168	176.4	33936	1	0	0	0	0	0	0	0	0	0	0	0	1998
10657	168	194.9	41264	0	1	0	0	0	0	0	0	0	0	0	0	1998
10613	168	186.6	39179	0	1	0	0	0	0	0	0	0	0	0	0	1998
10371	168	209.4	49823	0	1	0	0	0	0	0	0	0	0	0	0	1998
10391	168	205.0	47809	0	1	0	0	0	0	0	0	0	0	0	0	1998
10660	168	243.4	64790	0	0	1	0	0	0	0	0	0	0	0	0	1998
10641	168	229.5	57861	0	0	1	0	0	0	0	0	0	0	0	0	1998
10663	168	202.6	45698	0	0	1	0	0	0	0	0	0	0	0	0	1998
10528	168	237.0	61359	0	0	1	0	0	0	0	0	0	0	0	0	1998
10518	167	227.6	57539	0	0	0	1	0	0	0	0	0	0	0	0	1998
10647	168	209.9	49267	0	0	0	1	0	0	0	0	0	0	0	0	1998
10477	69	259.9	71446	0	0	0	1	0	0	0	0	0	0	0	0	1998
12942	13	126.4	16689	0	0	0	1	0	0	0	0	0	0	0	1	1998
10573	168	213.4	50470	0	0	0	0	1	0	0	0	0	0	0	0	1998
10411	168	234.8	60425	0	0	0	0	1	0	0	0	0	0	0	0	1998
10331	168	251.2	67786	0	0	0	0	1	0	0	0	0	0	0	0	1998
10457	168	251.3	67734	0	0	0	0	1	0	0	0	0	0	0	0	1998
10719	135	239.4	63743	0	0	0	0	1	0	0	0	0	0	0	1	1998
10496	168	231.8	58700	0	0	0	0	0	1	0	0	0	0	0	0	1998

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10690	168	253.5	68465	0	0	0	0	0	1	0	0	0	0	0	0	1998
10669	134	241.0	63971	0	0	0	0	0	1	0	0	0	0	0	1	1998
10545	146	233.9	60446	0	0	0	0	0	1	0	0	0	0	0	0	1998
10763	168	235.8	60731	0	0	0	0	0	0	1	0	0	0	0	0	1998
10686	168	251.2	68163	0	0	0	0	0	0	1	0	0	0	0	0	1998
10678	168	251.3	67749	0	0	0	0	0	0	1	0	0	0	0	0	1998
10792	154	264.0	76427	0	0	0	0	0	0	1	0	0	0	0	0	1998
10770	168	246.8	67200	0	0	0	0	0	0	0	1	0	0	0	0	1998
10840	168	240.9	63176	0	0	0	0	0	0	0	1	0	0	0	0	1998
11101	168	229.8	58271	0	0	0	0	0	0	0	1	0	0	0	0	1998
11028	168	238.7	63320	0	0	0	0	0	0	0	1	0	0	0	0	1998
10652	168	273.9	78098	0	0	0	0	0	0	0	1	0	0	0	0	1998
10772	157	222.8	55696	0	0	0	0	0	0	0	0	1	0	0	0	1998
10725	168	209.8	47428	0	0	0	0	0	0	0	0	1	0	0	0	1998
11071	142	213.4	48377	0	0	0	0	0	0	0	0	1	0	0	1	1998
10671	168	236.5	60544	0	0	0	0	0	0	0	0	1	0	0	0	1998
11260	24	216.8	52596	0	0	0	0	0	0	0	0	1	0	0	0	1998
11279	168	234.9	60121	0	0	0	0	0	0	0	0	0	1	0	0	1998
10915	168	184.6	38492	0	0	0	0	0	0	0	0	0	1	0	0	1998
10616	168	240.2	62106	0	0	0	0	0	0	0	0	0	1	0	0	1998
10836	169	178.0	33687	0	0	0	0	0	0	0	0	0	1	0	0	1998
11241	46	163.8	27811	0	0	0	0	0	0	0	0	0	0	1	0	1998
10834	97	237.1	61976	0	0	0	0	0	0	0	0	0	0	1	1	1998
10726	167	239.7	62983	0	0	0	0	0	0	0	0	0	0	1	0	1998
10388	168	251.0	67114	0	0	0	0	0	0	0	0	0	0	1	0	1998
10731	168	181.0	37056	0	0	0	0	0	0	0	0	0	0	1	0	1998
10699	168	218.8	53167	0	0	0	0	0	0	0	0	0	0	0	0	1998
10606	168	206.1	46963	0	0	0	0	0	0	0	0	0	0	0	0	1998
10573	168	197.2	42770	0	0	0	0	0	0	0	0	0	0	0	0	1998
10711	168	159.2	27797	0	0	0	0	0	0	0	0	0	0	0	0	1998
10489	24	212.0	48246	0	0	0	0	1	0	0	0	0	0	0	0	1998
10493	168	233.2	59731	1	0	0	0	0	0	0	0	0	0	0	0	1999
10901	168	186.5	38813	1	0	0	0	0	0	0	0	0	0	0	0	1999
10987	168	157.4	27151	1	0	0	0	0	0	0	0	0	0	0	0	1999
11079	168	149.8	24220	1	0	0	0	0	0	0	0	0	0	0	0	1999
11015	168	168.5	30545	0	1	0	0	0	0	0	0	0	0	0	0	1999
10985	168	173.0	33086	0	1	0	0	0	0	0	0	0	0	0	0	1999
10696	168	224.0	54377	0	1	0	0	0	0	0	0	0	0	0	0	1999
10871	168	204.9	46925	0	1	0	0	0	0	0	0	0	0	0	0	1999
11118	168	156.8	26531	0	0	1	0	0	0	0	0	0	0	0	0	1999
10779	168	194.3	41923	0	0	1	0	0	0	0	0	0	0	0	0	1999
10718	168	199.4	43824	0	0	1	0	0	0	0	0	0	0	0	0	1999
10780	112	220.7	53263	0	0	1	0	0	0	0	0	0	0	0	1	1999
10408	168	266.5	73209	0	0	1	0	0	0	0	0	0	0	0	0	1999
10495	26	221.8	55893	0	0	0	1	0	0	0	0	0	0	0	0	1999
10164	166	236.3	61472	0	0	0	1	0	0	0	0	0	0	0	1	1999
* 9147	168	206.0	48180	0	0	0	0	1	0	0	0	0	0	0	0	1999

Data Base for CRIST 6 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
*	9339	168	204.1	46604	0	0	0	0	1	0	0	0	0	0	0	0	1999
	11254	159	190.9	41135	0	0	0	0	1	0	0	0	0	0	0	0	1999
	10719	168	226.8	57330	0	0	0	0	1	0	0	0	0	0	0	0	1999
	10224	168	212.8	50396	0	0	0	0	1	0	0	0	0	0	0	0	1999
*	8907	168	239.3	62415	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10612	168	227.1	57552	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10166	168	225.3	56766	0	0	0	0	0	1	0	0	0	0	0	0	1999
	11745	144	217.7	52645	0	0	0	0	0	1	0	0	0	0	0	0	1999

Data Base for CRIST 6 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10307	168	314.1	114054	0	0	0	0	0	0	1	0	0	0	0	0	1996
	10406	98	340.2	130649	0	0	0	0	0	0	1	0	0	0	0	0	1996
	10610	126	351.9	141120	0	0	0	0	0	0	1	0	0	0	0	1	1996
	10340	168	317.9	115896	0	0	0	0	0	0	1	0	0	0	0	0	1996
	10427	163	335.5	130760	0	0	0	0	0	0	0	1	0	0	0	0	1996
	10393	165	323.7	122079	0	0	0	0	0	0	0	1	0	0	0	0	1996
	10449	163	319.1	119372	0	0	0	0	0	0	0	1	0	0	0	0	1996
	10300	168	323.3	120367	0	0	0	0	0	0	0	1	0	0	0	0	1996
	10532	168	261.3	79233	0	0	0	0	0	0	0	1	0	0	0	0	1996
	10428	168	356.4	146668	0	0	0	0	0	0	0	0	1	0	0	0	1996
	10693	123	254.1	78190	0	0	0	0	0	0	0	0	1	0	0	1	1996
	10392	163	309.4	113465	0	0	0	0	0	0	0	0	1	0	0	0	1996
	10341	168	311.0	114394	0	0	0	0	0	0	0	0	1	0	0	0	1996
	10781	24	199.5	40331	0	0	0	0	0	0	0	0	1	0	0	0	1996
	10638	167	243.2	66328	0	0	0	0	0	0	0	0	0	1	0	0	1996
	10660	168	235.0	60222	0	0	0	0	0	0	0	0	0	1	0	0	1996
	10408	168	290.0	97416	0	0	0	0	0	0	0	0	0	1	0	0	1996
	10266	169	310.8	107010	0	0	0	0	0	0	0	0	0	1	0	0	1996
	10396	168	263.2	77262	0	0	0	0	0	0	0	0	0	0	1	0	1996
	10515	168	274.9	85513	0	0	0	0	0	0	0	0	0	0	1	0	1996
	10539	163	269.2	80429	0	0	0	0	0	0	0	0	0	0	1	0	1996
	10504	95	332.6	121814	0	0	0	0	0	0	0	0	0	0	1	0	1996
	10448	168	285.2	91265	0	0	0	0	0	0	0	0	0	0	0	1	1996
	10660	106	231.0	60278	0	0	0	0	0	0	0	0	0	0	0	0	1996
	10088	38	280.7	93284	1	0	0	0	0	0	0	0	0	0	0	1	1997
	10332	166	309.0	108716	1	0	0	0	0	0	0	0	0	0	0	0	1997
	10378	159	387.8	163663	1	0	0	0	0	0	0	0	0	0	0	0	1997
	10455	97	267.8	79559	1	0	0	0	0	0	0	0	0	0	0	1	1997
	10497	135	311.1	114813	1	0	0	0	0	0	0	0	0	0	0	1	1997
	10267	165	301.8	102582	0	1	0	0	0	0	0	0	0	0	0	0	1997
	10430	133	341.3	133210	0	1	0	0	0	0	0	0	0	0	0	1	1997
	10556	168	284.9	92189	0	1	0	0	0	0	0	0	0	0	0	0	1997
	10443	102	277.4	88087	0	1	0	0	0	0	0	0	0	0	0	0	1997
	10627	104	259.7	74032	0	0	1	0	0	0	0	0	0	0	0	2	1997
	10636	140	221.6	54325	0	0	1	0	0	0	0	0	0	0	0	0	1997
	10624	131	247.2	66973	0	0	1	0	0	0	0	0	0	0	0	2	1997
	10558	168	278.4	83495	0	0	1	0	0	0	0	0	0	0	0	0	1997
	10358	167	343.1	131827	0	0	0	1	0	0	0	0	0	0	0	0	1997
	10304	166	357.9	143356	0	0	0	1	0	0	0	0	0	0	0	0	1997
	10558	142	352.2	137891	0	0	0	1	0	0	0	0	0	0	0	1	1997
	10192	63	373.8	155010	0	0	0	1	0	0	0	0	0	0	0	0	1997
*	20529	7	140.3	22105	0	0	0	0	1	0	0	0	0	0	0	1	1997
	11310	48	210.2	50548	0	0	0	0	0	1	0	0	0	0	0	1	1997
	10768	101	288.6	105293	0	0	0	0	0	1	0	0	0	0	0	2	1997
	10553	128	335.9	133952	0	0	0	0	0	1	0	0	0	0	0	1	1997
	10672	168	351.3	142934	0	0	0	0	0	1	0	0	0	0	0	0	1997
	10735	166	358.9	149824	0	0	0	0	0	0	1	0	0	0	0	0	1997

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10429	168	369.2	156851	0	0	0	0	0	0	1	0	0	0	0	0	1997
10577	168	355.0	145792	0	0	0	0	0	0	1	0	0	0	0	0	1997
10732	168	380.6	162265	0	0	0	0	0	0	1	0	0	0	0	0	1997
10625	122	320.7	126085	0	0	0	0	0	0	0	1	0	0	0	1	1997
10620	122	330.2	131125	0	0	0	0	0	0	0	1	0	0	0	1	1997
10238	168	415.8	185966	0	0	0	0	0	0	0	1	0	0	0	0	1997
9999	168	397.6	175594	0	0	0	0	0	0	0	1	0	0	0	0	1997
10221	168	379.3	163604	0	0	0	0	0	0	0	1	0	0	0	0	1997
10206	168	401.5	179966	0	0	0	0	0	0	0	0	1	0	0	0	1997
10357	150	390.5	173153	0	0	0	0	0	0	0	0	1	0	0	0	1997
9976	163	430.0	197475	0	0	0	0	0	0	0	0	1	0	0	0	1997
10263	168	374.6	156330	0	0	0	0	0	0	0	0	1	0	0	0	1997
10417	24	334.4	123221	0	0	0	0	0	0	0	0	1	0	0	0	1997
10440	118	345.6	133677	0	0	0	0	0	0	0	0	0	1	0	0	1997
10239	134	400.8	181371	0	0	0	0	0	0	0	0	0	1	0	1	1997
10008	168	364.4	153316	0	0	0	0	0	0	0	0	0	1	0	0	1997
10379	141	367.8	157382	0	0	0	0	0	0	0	0	0	1	0	1	1997
10247	157	361.1	150359	0	0	0	0	0	0	0	0	0	0	1	0	1997
10458	146	300.7	105465	0	0	0	0	0	0	0	0	0	0	1	0	1997
10188	168	388.9	165016	0	0	0	0	0	0	0	0	0	0	1	0	1997
10473	168	336.0	128873	0	0	0	0	0	0	0	0	0	0	1	0	1997
10049	29	311.7	112901	0	0	0	0	0	0	0	0	0	0	1	0	1997
10769	107	261.7	79032	0	0	0	0	0	0	0	0	0	0	0	1	1997
10556	128	244.5	74051	0	0	0	0	0	0	0	0	0	0	0	1	1997
10466	168	329.8	123668	1	0	0	0	0	0	0	0	0	0	0	0	1998
11493	33	257.6	74980	1	0	0	0	0	0	0	0	0	0	0	1	1998
10440	159	359.1	136046	1	0	0	0	0	0	0	0	0	0	0	1	1998
10384	168	402.8	173393	1	0	0	0	0	0	0	0	0	0	0	0	1998
10104	168	387.7	161630	1	0	0	0	0	0	0	0	0	0	0	0	1998
10019	168	414.7	180515	0	1	0	0	0	0	0	0	0	0	0	0	1998
10188	39	339.7	132661	0	1	0	0	0	0	0	0	0	0	0	0	1998
11457	25	245.6	70590	0	0	1	0	0	0	0	0	0	0	0	1	1998
10153	168	393.6	163232	0	0	1	0	0	0	0	0	0	0	0	0	1998
9963	168	436.7	198894	0	0	1	0	0	0	0	0	0	0	0	0	1998
10057	168	459.6	214840	0	0	1	0	0	0	0	0	0	0	0	0	1998
10013	167	457.4	213621	0	0	0	1	0	0	0	0	0	0	0	0	1998
10259	168	441.5	201502	0	0	0	1	0	0	0	0	0	0	0	0	1998
10252	146	464.8	220552	0	0	0	1	0	0	0	0	0	0	0	0	1998
10397	168	441.8	201211	0	0	0	1	0	0	0	0	0	0	0	0	1998
10497	168	436.2	199312	0	0	0	0	1	0	0	0	0	0	0	0	1998
10446	164	442.2	202421	0	0	0	0	1	0	0	0	0	0	0	0	1998
10410	168	470.0	222286	0	0	0	0	1	0	0	0	0	0	0	0	1998
10631	168	472.1	224105	0	0	0	0	1	0	0	0	0	0	0	0	1998
10666	168	433.7	195373	0	0	0	0	1	0	0	0	0	0	0	0	1998
10630	41	421.6	187752	0	0	0	0	0	1	0	0	0	0	0	0	1998
10428	152	433.6	198362	0	0	0	0	0	1	0	0	0	0	0	1	1998
9922	168	435.8	198747	0	0	0	0	0	1	0	0	0	0	0	0	1998

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10099	150	433.5	196430	0	0	0	0	0	1	0	0	0	0	0	0	1998
10090	168	429.6	192940	0	0	0	0	0	0	1	0	0	0	0	0	1998
10129	168	453.5	211263	0	0	0	0	0	0	1	0	0	0	0	0	1998
10200	168	430.3	194368	0	0	0	0	0	0	1	0	0	0	0	0	1998
10194	137	432.6	199913	0	0	0	0	0	0	1	0	0	0	0	1	1998
10243	168	435.1	197499	0	0	0	0	0	0	0	1	0	0	0	0	1998
10349	145	420.9	187767	0	0	0	0	0	0	0	1	0	0	0	0	1998
10351	95	389.8	167965	0	0	0	0	0	0	0	1	0	0	0	1	1998
10428	148	413.3	183622	0	0	0	0	0	0	0	1	0	0	0	1	1998
10385	121	445.5	203668	0	0	0	0	0	0	0	1	0	0	0	1	1998
10342	168	373.4	148411	0	0	0	0	0	0	0	0	1	0	0	0	1998
10531	90	359.1	145734	0	0	0	0	0	0	0	0	1	0	0	2	1998
10263	168	399.5	173690	0	0	0	0	0	0	0	0	1	0	0	0	1998
10316	168	443.2	202248	0	0	0	0	0	0	0	0	1	0	0	0	1998
11002	24	466.9	219085	0	0	0	0	0	0	0	0	1	0	0	0	1998
10321	168	426.4	187324	0	0	0	0	0	0	0	0	0	1	0	0	1998
10540	168	352.6	135320	0	0	0	0	0	0	0	0	0	1	0	0	1998
9952	48	402.1	175689	0	0	0	0	0	0	0	0	0	1	0	0	1998
10493	83	347.9	133782	0	0	0	0	0	0	0	0	0	1	0	1	1998
10368	168	396.8	171079	0	0	0	0	0	0	0	0	0	0	1	0	1998
10547	62	338.4	133558	0	0	0	0	0	0	0	0	0	0	1	2	1998
10218	168	415.9	182964	0	0	0	0	0	0	0	0	0	0	1	0	1998
10195	168	406.4	179027	0	0	0	0	0	0	0	0	0	0	1	0	1998
10037	168	386.5	162154	0	0	0	0	0	0	0	0	0	0	1	0	1998
10235	168	376.1	162539	0	0	0	0	0	0	0	0	0	0	0	0	1998
10056	168	419.7	186978	0	0	0	0	0	0	0	0	0	0	0	0	1998
10129	168	408.7	177678	0	0	0	0	0	0	0	0	0	0	0	0	1998
10114	168	353.6	137664	0	0	0	0	0	0	0	0	0	0	0	0	1998
10104	24	486.8	237146	0	0	0	0	1	0	0	0	0	0	0	0	1998
10185	165	396.2	167502	1	0	0	0	0	0	0	0	0	0	0	0	1999
10322	115	363.3	143630	1	0	0	0	0	0	0	0	0	0	0	1	1999
10299	168	319.3	110896	1	0	0	0	0	0	0	0	0	0	0	0	1999
10226	168	338.1	124012	1	0	0	0	0	0	0	0	0	0	0	0	1999
10146	24	306.3	105374	0	1	0	0	0	0	0	0	0	0	0	0	1999
10792	77	386.7	162144	0	1	0	0	0	0	0	0	0	0	0	1	1999
10273	168	351.9	132504	0	0	1	0	0	0	0	0	0	0	0	0	1999
10069	168	446.9	204598	0	0	1	0	0	0	0	0	0	0	0	0	1999
10312	168	424.8	187757	0	0	1	0	0	0	0	0	0	0	0	0	1999
10405	79	400.0	174708	0	0	1	0	0	0	0	0	0	0	0	2	1999
10063	168	450.7	208403	0	0	1	0	0	0	0	0	0	0	0	0	1999
10404	105	403.1	176277	0	0	0	1	0	0	0	0	0	0	0	1	1999
10074	168	477.5	228760	0	0	0	1	0	0	0	0	0	0	0	0	1999
10061	141	454.7	211982	0	0	0	1	0	0	0	0	0	0	0	1	1999
10217	121	423.3	186336	0	0	0	1	0	0	0	0	0	0	0	1	1999
10186	168	421.1	184591	0	0	0	0	1	0	0	0	0	0	0	0	1999
10177	168	380.4	156625	0	0	0	0	1	0	0	0	0	0	0	0	1999
10165	168	396.4	167147	0	0	0	0	1	0	0	0	0	0	0	0	1999

Data Base for CRIST 7 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10299	168	415.0	178822	0	0	0	0	1	0	0	0	0	0	0	0	1999
	10225	168	395.5	165707	0	0	0	0	1	0	0	0	0	0	0	0	1999
*	9330	153	392.4	164114	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10280	156	415.2	178337	0	0	0	0	0	1	0	0	0	0	0	0	1999
	10263	103	393.6	169047	0	0	0	0	0	1	0	0	0	0	0	2	1999
	10217	144	441.9	197479	0	0	0	0	0	1	0	0	0	0	0	0	1999

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10238	168	151.6	23243	0	0	0	0	0	0	1	0	0	0	0	0	1996
10224	168	157.4	24844	0	0	0	0	0	0	1	0	0	0	0	0	1996
10184	168	158.3	25073	0	0	0	0	0	0	1	0	0	0	0	0	1996
10135	168	156.6	24665	0	0	0	0	0	0	1	0	0	0	0	0	1996
10222	168	155.3	24349	0	0	0	0	0	0	0	1	0	0	0	0	1996
10192	168	155.7	24389	0	0	0	0	0	0	0	1	0	0	0	0	1996
10345	168	149.9	22838	0	0	0	0	0	0	0	1	0	0	0	0	1996
10259	168	148.6	22458	0	0	0	0	0	0	0	1	0	0	0	0	1996
10361	168	145.0	21700	0	0	0	0	0	0	0	1	0	0	0	0	1996
10504	168	141.6	20879	0	0	0	0	0	0	0	0	1	0	0	0	1996
10082	168	144.4	21594	0	0	0	0	0	0	0	0	1	0	0	0	1996
10148	168	144.1	21626	0	0	0	0	0	0	0	0	1	0	0	0	1996
10145	168	144.6	21786	0	0	0	0	0	0	0	0	1	0	0	0	1996
10286	24	144.4	21518	0	0	0	0	0	0	0	0	1	0	0	0	1996
10153	168	141.6	21123	0	0	0	0	0	0	0	0	0	1	0	0	1996
10248	168	137.4	19856	0	0	0	0	0	0	0	0	0	1	0	0	1996
10102	168	145.0	21646	0	0	0	0	0	0	0	0	0	1	0	0	1996
10061	169	147.9	22404	0	0	0	0	0	0	0	0	0	1	0	0	1996
9989	95	146.0	21881	0	0	0	0	0	0	0	0	0	0	1	0	1996
10096	62	151.9	23514	0	0	0	0	0	0	0	0	0	0	1	1	1996
10019	168	153.2	23688	0	0	0	0	0	0	0	0	0	0	1	0	1996
10017	168	144.9	21688	0	0	0	0	0	0	0	0	0	0	1	0	1996
10079	168	130.6	18405	0	0	0	0	0	0	0	0	0	0	1	0	1996
10110	168	134.4	19204	0	0	0	0	0	0	0	0	0	0	0	0	1996
10184	168	131.0	18364	0	0	0	0	0	0	0	0	0	0	0	0	1996
10142	168	135.2	19396	0	0	0	0	0	0	0	0	0	0	0	0	1996
10315	167	92.4	9657	0	0	0	0	0	0	0	0	0	0	0	0	1996
10947	25	104.5	12649	1	0	0	0	0	0	0	0	0	0	0	1	1997
10316	168	130.6	18238	1	0	0	0	0	0	0	0	0	0	0	0	1997
10210	168	145.7	22041	1	0	0	0	0	0	0	0	0	0	0	0	1997
10293	168	125.5	17385	1	0	0	0	0	0	0	0	0	0	0	0	1997
10313	168	129.4	18164	1	0	0	0	0	0	0	0	0	0	0	0	1997
10263	168	121.0	16213	0	1	0	0	0	0	0	0	0	0	0	0	1997
10380	168	130.3	18310	0	1	0	0	0	0	0	0	0	0	0	0	1997
10295	168	114.4	14483	0	1	0	0	0	0	0	0	0	0	0	0	1997
10339	168	111.8	14237	0	1	0	0	0	0	0	0	0	0	0	0	1997
10655	168	90.6	9470	0	0	1	0	0	0	0	0	0	0	0	0	1997
10450	58	86.6	8717	0	0	1	0	0	0	0	0	0	0	0	0	1997
11144	20	107.3	12534	0	0	1	0	0	0	0	0	0	0	0	1	1997
9994	167	156.3	24582	0	0	0	1	0	0	0	0	0	0	0	0	1997
10050	168	149.8	22865	0	0	0	1	0	0	0	0	0	0	0	0	1997
10019	168	149.0	22623	0	0	0	1	0	0	0	0	0	0	0	0	1997
10088	168	150.3	22982	0	0	0	1	0	0	0	0	0	0	0	0	1997
10090	168	138.2	20423	0	0	0	0	1	0	0	0	0	0	0	0	1997
10150	168	130.5	18329	0	0	0	0	1	0	0	0	0	0	0	0	1997
10190	116	139.8	20685	0	0	0	0	1	0	0	0	0	0	0	1	1997
10086	168	138.0	20104	0	0	0	0	1	0	0	0	0	0	0	0	1997

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10292	168	135.7	19550	0	0	0	0	1	0	0	0	0	0	0	0	1997
10224	168	127.2	17639	0	0	0	0	0	1	0	0	0	0	0	0	1997
10191	168	130.7	18658	0	0	0	0	0	1	0	0	0	0	0	0	1997
10255	168	133.0	19105	0	0	0	0	0	1	0	0	0	0	0	0	1997
10221	168	137.8	20173	0	0	0	0	0	1	0	0	0	0	0	0	1997
10387	142	136.3	19820	0	0	0	0	0	0	1	0	0	0	0	1	1997
10361	168	141.5	20848	0	0	0	0	0	0	1	0	0	0	0	0	1997
10397	168	141.0	20741	0	0	0	0	0	0	1	0	0	0	0	0	1997
10358	168	151.0	23090	0	0	0	0	0	0	1	0	0	0	0	0	1997
10238	168	138.6	20323	0	0	0	0	0	0	0	1	0	0	0	0	1997
10255	168	138.5	20207	0	0	0	0	0	0	0	1	0	0	0	0	1997
10138	100	152.2	23372	0	0	0	0	0	0	0	1	0	0	0	0	1997
10577	78	120.5	16586	0	0	0	0	0	0	0	1	0	0	0	1	1997
10229	168	140.6	20642	0	0	0	0	0	0	0	1	0	0	0	0	1997
10196	168	139.8	20585	0	0	0	0	0	0	0	0	1	0	0	0	1997
10153	168	147.3	22330	0	0	0	0	0	0	0	0	1	0	0	0	1997
10130	168	156.6	24597	0	0	0	0	0	0	0	0	1	0	0	0	1997
10235	168	146.3	22121	0	0	0	0	0	0	0	0	1	0	0	0	1997
10272	24	142.3	21214	0	0	0	0	0	0	0	0	1	0	0	0	1997
10223	168	142.5	21190	0	0	0	0	0	0	0	0	0	1	0	0	1997
10170	168	151.8	23239	0	0	0	0	0	0	0	0	0	1	0	0	1997
10208	168	138.4	20265	0	0	0	0	0	0	0	0	0	1	0	0	1997
10245	73	137.2	20080	0	0	0	0	0	0	0	0	0	1	0	0	1997
10494	71	129.5	18433	0	0	0	0	0	0	0	0	0	0	1	1	1997
10367	168	98.3	10150	0	0	0	0	0	0	0	0	0	0	1	0	1997
10312	168	117.4	14886	0	0	0	0	0	0	0	0	0	0	1	0	1997
10299	168	146.4	21916	0	0	0	0	0	0	0	0	0	0	1	0	1997
10255	168	126.1	17284	0	0	0	0	0	0	0	0	0	0	1	0	1997
10401	168	146.0	21998	0	0	0	0	0	0	0	0	0	0	0	0	1997
10227	168	147.3	22270	0	0	0	0	0	0	0	0	0	0	0	0	1997
10264	168	141.6	21028	0	0	0	0	0	0	0	0	0	0	0	0	1997
10338	168	116.5	15378	0	0	0	0	0	0	0	0	0	0	0	0	1997
10233	168	122.2	16298	1	0	0	0	0	0	0	0	0	0	0	0	1998
10227	168	130.0	18360	1	0	0	0	0	0	0	0	0	0	0	0	1998
10300	168	134.8	19185	1	0	0	0	0	0	0	0	0	0	0	0	1998
10470	168	131.5	18355	1	0	0	0	0	0	0	0	0	0	0	0	1998
10559	168	127.4	17502	1	0	0	0	0	0	0	0	0	0	0	0	1998
10423	168	137.9	19903	0	1	0	0	0	0	0	0	0	0	0	0	1998
10391	168	117.8	15442	0	1	0	0	0	0	0	0	0	0	0	0	1998
10357	168	125.5	17185	0	1	0	0	0	0	0	0	0	0	0	0	1998
10419	168	118.2	15750	0	1	0	0	0	0	0	0	0	0	0	0	1998
10512	145	130.7	18853	0	0	1	0	0	0	0	0	0	0	0	1	1998
10311	168	140.3	20615	0	0	1	0	0	0	0	0	0	0	0	0	1998
10236	168	140.0	20604	0	0	1	0	0	0	0	0	0	0	0	0	1998
10208	168	139.4	20476	0	0	1	0	0	0	0	0	0	0	0	0	1998
10183	167	149.0	22661	0	0	0	1	0	0	0	0	0	0	0	0	1998
10224	168	136.1	19721	0	0	0	1	0	0	0	0	0	0	0	0	1998

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10218	168	148.2	22450	0	0	0	1	0	0	0	0	0	0	0	0	1998
10154	168	137.2	20007	0	0	0	1	0	0	0	0	0	0	0	0	1998
10002	168	153.2	23707	0	0	0	0	1	0	0	0	0	0	0	0	1998
10357	168	155.1	24120	0	0	0	0	1	0	0	0	0	0	0	0	1998
10320	168	155.5	24210	0	0	0	0	1	0	0	0	0	0	0	0	1998
10276	168	153.6	23705	0	0	0	0	1	0	0	0	0	0	0	0	1998
10306	168	152.9	23514	0	0	0	0	1	0	0	0	0	0	0	0	1998
10160	25	145.5	22061	0	0	0	0	0	1	0	0	0	0	0	0	1998
10386	95	150.5	23182	0	0	0	0	0	1	0	0	0	0	0	1	1998
10161	168	155.0	24113	0	0	0	0	0	1	0	0	0	0	0	0	1998
10047	168	156.4	24505	0	0	0	0	0	1	0	0	0	0	0	0	1998
10084	168	153.3	23709	0	0	0	0	0	0	1	0	0	0	0	0	1998
10093	168	154.1	23798	0	0	0	0	0	0	1	0	0	0	0	0	1998
10429	168	155.9	24350	0	0	0	0	0	0	1	0	0	0	0	0	1998
10232	168	156.3	24481	0	0	0	0	0	0	1	0	0	0	0	0	1998
10354	168	154.5	23900	0	0	0	0	0	0	0	1	0	0	0	0	1998
10193	168	154.2	23834	0	0	0	0	0	0	0	1	0	0	0	0	1998
10010	168	155.2	24085	0	0	0	0	0	0	0	1	0	0	0	0	1998
10184	168	153.9	23779	0	0	0	0	0	0	0	1	0	0	0	0	1998
10019	168	154.9	24039	0	0	0	0	0	0	0	1	0	0	0	0	1998
10301	168	154.9	24017	0	0	0	0	0	0	0	0	1	0	0	0	1998
10116	168	150.8	23099	0	0	0	0	0	0	0	0	1	0	0	0	1998
10062	72	147.9	22243	0	0	0	0	0	0	0	0	1	0	0	0	1998
10312	112	146.6	21989	0	0	0	0	0	0	0	0	1	0	0	1	1998
10510	24	150.2	22608	0	0	0	0	0	0	0	0	1	0	0	0	1998
10331	168	152.8	23468	0	0	0	0	0	0	0	0	0	1	0	0	1998
10004	168	147.5	22219	0	0	0	0	0	0	0	0	0	1	0	0	1998
10306	168	155.6	24293	0	0	0	0	0	0	0	0	0	1	0	0	1998
10037	169	153.4	23641	0	0	0	0	0	0	0	0	0	1	0	0	1998
9979	168	150.6	22849	0	0	0	0	0	0	0	0	0	0	1	0	1998
10089	168	151.8	23243	0	0	0	0	0	0	0	0	0	0	1	0	1998
10003	168	141.1	20239	0	0	0	0	0	0	0	0	0	0	1	0	1998
9887	144	146.8	22213	0	0	0	0	0	0	0	0	0	0	1	1	1998
9978	168	136.6	19550	0	0	0	0	0	0	0	0	0	0	1	0	1998
9896	168	141.0	20608	0	0	0	0	0	0	0	0	0	0	0	0	1998
10259	142	145.5	21957	0	0	0	0	0	0	0	0	0	0	0	1	1998
10253	168	140.5	20567	0	0	0	0	0	0	0	0	0	0	0	0	1998
9976	168	136.6	19356	0	0	0	0	0	0	0	0	0	0	0	0	1998
9876	24	148.6	22178	0	0	0	0	1	0	0	0	0	0	0	0	1998
10053	168	154.2	23977	1	0	0	0	0	0	0	0	0	0	0	0	1999
9994	168	147.1	22167	1	0	0	0	0	0	0	0	0	0	0	0	1999
10130	168	136.0	19443	1	0	0	0	0	0	0	0	0	0	0	0	1999
10017	144	135.6	19427	1	0	0	0	0	0	0	0	0	0	0	0	1999
10004	114	126.0	17341	0	1	0	0	0	0	0	0	0	0	0	1	1999
11244	52	107.9	13960	0	0	0	1	0	0	0	0	0	0	0	1	1999
10192	68	108.0	12633	0	0	0	1	0	0	0	0	0	0	0	1	1999
9550	168	148.2	22163	0	0	0	1	0	0	0	0	0	0	0	0	1999

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9811	100	145.3	22106	0	0	0	0	1	0	0	0	0	0	0	1	1999
9887	168	145.5	21922	0	0	0	0	1	0	0	0	0	0	0	0	1999
9681	168	143.6	21454	0	0	0	0	1	0	0	0	0	0	0	0	1999
9885	168	144.7	21631	0	0	0	0	1	0	0	0	0	0	0	0	1999
10230	113	138.7	20405	0	0	0	0	1	0	0	0	0	0	0	1	1999
9941	168	149.3	22693	0	0	0	0	0	1	0	0	0	0	0	0	1999
10150	168	153.5	23731	0	0	0	0	0	1	0	0	0	0	0	0	1999
10061	168	145.8	22147	0	0	0	0	0	1	0	0	0	0	0	0	1999
10104	144	152.5	23755	0	0	0	0	0	1	0	0	0	0	0	0	1999

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10308	168	172.4	30540	0	0	0	0	0	0	1	0	0	0	0	0	1996
10407	168	180.9	33028	0	0	0	0	0	0	1	0	0	0	0	0	1996
10474	148	179.9	32962	0	0	0	0	0	0	1	0	0	0	0	0	1996
10418	155	175.9	31924	0	0	0	0	0	0	1	0	0	0	0	0	1996
10478	168	177.3	32099	0	0	0	0	0	0	0	1	0	0	0	0	1996
10413	168	177.6	32033	0	0	0	0	0	0	0	1	0	0	0	0	1996
10523	168	171.0	30187	0	0	0	0	0	0	0	1	0	0	0	0	1996
10543	168	169.9	29848	0	0	0	0	0	0	0	1	0	0	0	0	1996
10568	168	163.8	28367	0	0	0	0	0	0	0	1	0	0	0	0	1996
10638	154	156.0	26482	0	0	0	0	0	0	0	0	1	0	0	0	1996
10357	158	157.2	26715	0	0	0	0	0	0	0	0	1	0	0	1	1996
10278	168	163.0	28333	0	0	0	0	0	0	0	0	1	0	0	0	1996
10352	168	161.5	27867	0	0	0	0	0	0	0	0	1	0	0	0	1996
10428	24	163.0	28271	0	0	0	0	0	0	0	0	1	0	0	0	1996
10305	168	156.9	26609	0	0	0	0	0	0	0	0	0	1	0	0	1996
10221	168	151.6	24906	0	0	0	0	0	0	0	0	0	1	0	0	1996
10132	164	156.8	26268	0	0	0	0	0	0	0	0	0	1	0	0	1996
10239	143	164.5	28949	0	0	0	0	0	0	0	0	0	1	0	1	1996
10140	168	171.2	30246	0	0	0	0	0	0	0	0	0	0	1	0	1996
10080	168	177.0	31769	0	0	0	0	0	0	0	0	0	0	1	0	1996
10290	73	178.5	32575	0	0	0	0	0	0	0	0	0	0	1	0	1996
10410	61	147.7	23811	0	0	0	0	0	0	0	0	0	0	1	1	1996
10068	168	141.4	22187	0	0	0	0	0	0	0	0	0	0	1	0	1996
9917	168	148.9	24054	0	0	0	0	0	0	0	0	0	0	0	0	1996
10103	168	147.4	23656	0	0	0	0	0	0	0	0	0	0	0	0	1996
10224	140	142.1	22919	0	0	0	0	0	0	0	0	0	0	0	1	1996
10418	124	89.1	9030	0	0	0	0	0	0	0	0	0	0	0	1	1996
10233	168	115.3	15541	1	0	0	0	0	0	0	0	0	0	0	0	1997
10224	168	136.7	20724	1	0	0	0	0	0	0	0	0	0	0	0	1997
10038	168	162.6	27939	1	0	0	0	0	0	0	0	0	0	0	0	1997
10280	168	132.0	19932	1	0	0	0	0	0	0	0	0	0	0	0	1997
10372	168	131.0	19863	1	0	0	0	0	0	0	0	0	0	0	0	1997
10178	168	129.0	18776	0	1	0	0	0	0	0	0	0	0	0	0	1997
10281	168	134.4	20432	0	1	0	0	0	0	0	0	0	0	0	0	1997
10519	60	114.1	15578	0	1	0	0	0	0	0	0	0	0	0	1	1997
10219	168	113.3	15116	0	1	0	0	0	0	0	0	0	0	0	0	1997
10315	168	91.0	9700	0	0	1	0	0	0	0	0	0	0	0	0	1997
10398	168	85.7	8514	0	0	1	0	0	0	0	0	0	0	0	0	1997
10271	168	99.0	11206	0	0	1	0	0	0	0	0	0	0	0	0	1997
10126	24	126.6	18440	0	0	1	0	0	0	0	0	0	0	0	0	1997
10285	95	162.5	27958	0	0	0	1	0	0	0	0	0	0	0	1	1997
10098	168	165.3	28668	0	0	0	1	0	0	0	0	0	0	0	0	1997
10044	168	170.5	30248	0	0	0	1	0	0	0	0	0	0	0	0	1997
10132	168	149.4	24726	0	0	0	0	1	0	0	0	0	0	0	0	1997
10256	168	139.8	22011	0	0	0	0	1	0	0	0	0	0	0	0	1997
10166	168	153.4	25791	0	0	0	0	1	0	0	0	0	0	0	0	1997
9933	168	152.8	25617	0	0	0	0	1	0	0	0	0	0	0	0	1997

Data Base for SMITH 2 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10344	168	146.9	24070	0	0	0	0	1	0	0	0	0	0	0	0	1997
	10266	168	131.9	19901	0	0	0	0	0	1	0	0	0	0	0	0	1997
	10210	168	143.5	23380	0	0	0	0	0	1	0	0	0	0	0	0	1997
	10349	168	147.5	24373	0	0	0	0	0	1	0	0	0	0	0	0	1997
	10340	146	151.1	25219	0	0	0	0	0	1	0	0	0	0	0	0	1997
	10354	168	155.2	26245	0	0	0	0	0	0	1	0	0	0	0	0	1997
	10237	168	156.6	26434	0	0	0	0	0	0	1	0	0	0	0	0	1997
	10255	168	155.5	26141	0	0	0	0	0	0	1	0	0	0	0	0	1997
	10200	168	168.9	29484	0	0	0	0	0	0	1	0	0	0	0	0	1997
	10125	168	154.5	25964	0	0	0	0	0	0	0	1	0	0	0	0	1997
	10151	168	152.3	25448	0	0	0	0	0	0	0	1	0	0	0	0	1997
	10116	145	168.6	29387	0	0	0	0	0	0	0	1	0	0	0	0	1997
	10164	168	165.8	29050	0	0	0	0	0	0	0	1	0	0	0	0	1997
	10103	168	156.9	26571	0	0	0	0	0	0	0	1	0	0	0	0	1997
	10020	168	156.1	26573	0	0	0	0	0	0	0	0	1	0	0	0	1997
	10067	96	160.7	27555	0	0	0	0	0	0	0	0	1	0	0	0	1997
	10085	92	176.8	31862	0	0	0	0	0	0	0	0	1	0	0	1	1997
	9996	168	166.0	28953	0	0	0	0	0	0	0	0	1	0	0	0	1997
	9842	24	163.4	28585	0	0	0	0	0	0	0	0	1	0	0	0	1997
	9986	168	162.1	28097	0	0	0	0	0	0	0	0	0	1	0	0	1997
	9939	168	173.4	30564	0	0	0	0	0	0	0	0	0	1	0	0	1997
	9978	168	155.4	26152	0	0	0	0	0	0	0	0	0	1	0	0	1997
	10114	169	162.9	28099	0	0	0	0	0	0	0	0	0	1	0	0	1997
	10141	168	155.3	25961	0	0	0	0	0	0	0	0	0	0	1	0	1997
	10156	145	157.5	26660	0	0	0	0	0	0	0	0	0	0	1	0	1997
	9958	168	172.2	30675	0	0	0	0	0	0	0	0	0	0	1	0	1997
	10024	168	168.5	29506	0	0	0	0	0	0	0	0	0	0	1	0	1997
	10081	168	136.5	21002	0	0	0	0	0	0	0	0	0	0	1	0	1997
	10181	134	167.5	29827	0	0	0	0	0	0	0	0	0	0	0	1	1997
	10100	137	167.9	29694	0	0	0	0	0	0	0	0	0	0	0	0	1997
	10079	118	153.7	26164	0	0	0	0	0	0	0	0	0	0	0	1	1997
	10189	95	131.5	20649	0	0	0	0	0	0	0	0	0	0	0	1	1997
	10068	168	148.8	24665	1	0	0	0	0	0	0	0	0	0	0	0	1998
	10135	139	147.9	23646	1	0	0	0	0	0	0	0	0	0	0	1	1998
	10120	168	158.0	26116	1	0	0	0	0	0	0	0	0	0	0	0	1998
	10056	168	175.2	30765	1	0	0	0	0	0	0	0	0	0	0	0	1998
	10332	168	174.7	31139	1	0	0	0	0	0	0	0	0	0	0	0	1998
	10198	168	173.4	30473	0	1	0	0	0	0	0	0	0	0	0	0	1998
	9919	168	170.1	29092	0	1	0	0	0	0	0	0	0	0	0	0	1998
	9951	168	166.8	28540	0	1	0	0	0	0	0	0	0	0	0	0	1998
	10026	70	162.9	28013	0	1	0	0	0	0	0	0	0	0	0	0	1998
*	13989	21	81.1	9097	0	0	0	0	1	0	0	0	0	0	0	2	1998
	10568	93	132.1	20017	0	0	0	0	1	0	0	0	0	0	0	1	1998
	10166	46	177.0	32284	0	0	0	0	1	0	0	0	0	0	0	0	1998
	10333	66	149.3	26043	0	0	0	0	1	0	0	0	0	0	0	1	1998
	9934	168	187.5	35192	0	0	0	0	0	1	0	0	0	0	0	0	1998
*	1000	168	188.5	35654	0	0	0	0	0	1	0	0	0	0	0	0	1998

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10092	168	187.4	35145	0	0	0	0	0	1	0	0	0	0	0	0	1998
9964	168	182.9	33905	0	0	0	0	0	1	0	0	0	0	0	0	1998
9866	163	182.9	34168	0	0	0	0	0	0	1	0	0	0	0	0	1998
9918	168	187.1	35026	0	0	0	0	0	0	1	0	0	0	0	0	1998
10196	168	186.9	34947	0	0	0	0	0	0	1	0	0	0	0	0	1998
10150	168	136.9	20988	0	0	0	0	0	0	1	0	0	0	0	0	1998
10053	168	185.7	34485	0	0	0	0	0	0	0	1	0	0	0	0	1998
10085	168	184.9	34241	0	0	0	0	0	0	0	1	0	0	0	0	1998
10007	168	187.0	35011	0	0	0	0	0	0	0	1	0	0	0	0	1998
9981	168	183.5	33767	0	0	0	0	0	0	0	1	0	0	0	0	1998
9890	168	186.4	34769	0	0	0	0	0	0	0	1	0	0	0	0	1998
9935	168	182.4	33329	0	0	0	0	0	0	0	0	1	0	0	0	1998
9876	168	179.2	32632	0	0	0	0	0	0	0	0	1	0	0	0	1998
9931	168	187.0	34995	0	0	0	0	0	0	0	0	1	0	0	0	1998
9939	168	183.0	33526	0	0	0	0	0	0	0	0	1	0	0	0	1998
10153	24	178.2	31776	0	0	0	0	0	0	0	0	1	0	0	0	1998
9851	168	183.9	33884	0	0	0	0	0	0	0	0	0	1	0	0	1998
9930	168	178.0	32255	0	0	0	0	0	0	0	0	0	1	0	0	1998
9942	168	182.4	33413	0	0	0	0	0	0	0	0	0	1	0	0	1998
9911	169	181.8	33263	0	0	0	0	0	0	0	0	0	1	0	0	1998
9928	168	183.2	33638	0	0	0	0	0	0	0	0	0	0	1	0	1998
9998	168	184.7	34171	0	0	0	0	0	0	0	0	0	0	1	0	1998
9982	168	184.0	33884	0	0	0	0	0	0	0	0	0	0	1	0	1998
9871	168	182.8	33550	0	0	0	0	0	0	0	0	0	0	1	0	1998
9992	168	182.5	33335	0	0	0	0	0	0	0	0	0	0	1	0	1998
9954	168	180.7	32713	0	0	0	0	0	0	0	0	0	0	0	0	1998
10136	19	180.3	32612	0	0	0	0	0	0	0	0	0	0	0	0	1998
10113	114	164.0	28373	0	0	0	0	0	0	0	0	0	0	0	1	1998
9986	168	165.2	28367	0	0	0	0	0	0	0	0	0	0	0	0	1998
10041	24	184.6	34106	0	0	0	0	1	0	0	0	0	0	0	0	1998
9917	167	184.5	34329	1	0	0	0	0	0	0	0	0	0	0	0	1999
9985	168	180.4	33074	1	0	0	0	0	0	0	0	0	0	0	0	1999
9924	168	176.4	31654	1	0	0	0	0	0	0	0	0	0	0	0	1999
9888	168	174.3	31246	1	0	0	0	0	0	0	0	0	0	0	0	1999
9956	168	173.6	31062	0	1	0	0	0	0	0	0	0	0	0	0	1999
9969	168	166.2	29058	0	1	0	0	0	0	0	0	0	0	0	0	1999
10131	168	181.2	33279	0	1	0	0	0	0	0	0	0	0	0	0	1999
10096	168	184.0	33904	0	1	0	0	0	0	0	0	0	0	0	0	1999
10044	168	183.1	33862	0	0	1	0	0	0	0	0	0	0	0	0	1999
9963	168	187.1	35089	0	0	1	0	0	0	0	0	0	0	0	0	1999
9979	168	187.3	35091	0	0	1	0	0	0	0	0	0	0	0	0	1999
9983	168	186.2	34682	0	0	1	0	0	0	0	0	0	0	0	0	1999
10082	168	185.0	34327	0	0	1	0	0	0	0	0	0	0	0	0	1999
9850	167	181.6	33137	0	0	0	1	0	0	0	0	0	0	0	0	1999
9991	168	181.3	32923	0	0	0	1	0	0	0	0	0	0	0	0	1999
9958	168	184.9	34272	0	0	0	1	0	0	0	0	0	0	0	0	1999
10038	168	184.2	33985	0	0	0	1	0	0	0	0	0	0	0	0	1999

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10041	168	183.8	33884	0	0	0	0	1	0	0	0	0	0	0	0	1999
10682	22	165.3	29274	0	0	0	0	1	0	0	0	0	0	0	0	1999
10086	143	174.1	31307	0	0	0	0	1	0	0	0	0	0	0	1	1999
10196	168	182.5	33810	0	0	0	0	1	0	0	0	0	0	0	0	1999
10094	168	182.4	33508	0	0	0	0	0	1	0	0	0	0	0	0	1999
10168	168	185.1	34306	0	0	0	0	0	1	0	0	0	0	0	0	1999
10094	168	174.8	31554	0	0	0	0	0	1	0	0	0	0	0	0	1999
10132	144	185.6	34450	0	0	0	0	0	1	0	0	0	0	0	0	1999

Data Base for SMITH 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10394	153	333.2	135606	0	0	0	0	0	0	1	0	0	0	0	1	1996	11215
10247	168	365.6	156769	0	0	0	0	0	0	1	0	0	0	0	0	1996	11095
10242	138	397.7	177299	0	0	0	0	0	0	1	0	0	0	0	1	1996	11210
9961	168	371.8	161217	0	0	0	0	0	0	1	0	0	0	0	0	1996	11319
10138	168	368.4	159178	0	0	0	0	0	0	0	1	0	0	0	0	1996	11468
10217	168	364.0	157202	0	0	0	0	0	0	0	1	0	0	0	0	1996	11355
10410	168	360.3	156432	0	0	0	0	0	0	0	1	0	0	0	0	1996	11256
10309	168	337.6	140366	0	0	0	0	0	0	0	1	0	0	0	0	1996	11100
10813	168	284.6	105093	0	0	0	0	0	0	0	1	0	0	0	0	1996	11128
10520	168	331.3	132807	0	0	0	0	0	0	0	0	1	0	0	0	1996	11156
10819	168	361.1	133300	0	0	0	0	0	0	0	0	1	0	0	0	1996	9544
10768	168	347.5	121243	0	0	0	0	0	0	0	0	1	0	0	0	1996	9359
10480	119	356.3	128460	0	0	0	0	0	0	0	0	1	0	0	0	1996	9678
13434	19	186.9	38605	0	0	0	0	0	0	0	0	0	1	0	1	1996	9080
10994	168	313.4	102118	0	0	0	0	0	0	0	0	0	1	0	0	1996	9337
10607	98	423.4	184613	0	0	0	0	0	0	0	0	0	1	0	1	1996	9376
10564	169	441.8	196945	0	0	0	0	0	0	0	0	0	1	0	0	1996	9342
10623	168	419.7	179445	0	0	0	0	0	0	0	0	0	0	1	0	1996	9320
10656	168	400.6	162702	0	0	0	0	0	0	0	0	0	0	1	0	1996	9345
10395	168	427.5	183049	0	0	0	0	0	0	0	0	0	0	1	0	1996	9398
10255	76	367.3	136582	0	0	0	0	0	0	0	0	0	0	1	0	1996	9179
10661	144	396.5	163244	0	0	0	0	0	0	0	0	0	0	1	1	1996	9443
10595	168	451.8	205622	0	0	0	0	0	0	0	0	0	0	0	0	1996	9491
10556	168	427.0	187822	0	0	0	0	0	0	0	0	0	0	0	0	1996	9339
10447	168	441.7	198347	0	0	0	0	0	0	0	0	0	0	0	0	1996	9355
10457	168	393.6	163949	0	0	0	0	0	0	0	0	0	0	0	0	1996	9261
10779	168	401.5	165701	1	0	0	0	0	0	0	0	0	0	0	0	1997	9374
10835	95	349.3	124956	1	0	0	0	0	0	0	0	0	0	0	0	1997	9262
10905	152	320.1	107643	0	1	0	0	0	0	0	0	0	0	0	1	1997	9336
10571	167	383.5	150753	0	1	0	0	0	0	0	0	0	0	0	0	1997	9279
10777	97	377.7	155150	0	1	0	0	0	0	0	0	0	0	0	1	1997	9210
10514	138	381.1	158484	0	1	0	0	0	0	0	0	0	0	0	1	1997	9123
10561	130	361.5	145363	0	0	1	0	0	0	0	0	0	0	0	1	1997	9389
10528	168	389.9	163244	0	0	1	0	0	0	0	0	0	0	0	0	1997	9235
10401	168	408.4	174168	0	0	1	0	0	0	0	0	0	0	0	0	1997	9199
10362	168	425.7	185977	0	0	1	0	0	0	0	0	0	0	0	0	1997	9257
10574	89	406.4	173770	0	0	0	1	0	0	0	0	0	0	0	1	1997	9293
10590	168	428.0	185933	0	0	0	1	0	0	0	0	0	0	0	0	1997	9170
10352	168	449.3	202671	0	0	0	1	0	0	0	0	0	0	0	0	1997	9227
10699	168	443.9	197621	0	0	0	1	0	0	0	0	0	0	0	0	1997	9492
10404	93	408.0	169639	0	0	0	0	1	0	0	0	0	0	0	0	1997	11195
10946	67	340.3	128531	0	0	0	0	1	0	0	0	0	0	0	1	1997	9488
10367	168	424.3	184712	0	0	0	0	1	0	0	0	0	0	0	0	1997	9459
10513	168	418.2	178740	0	0	0	0	1	0	0	0	0	0	0	0	1997	9485
10499	168	349.5	125242	0	0	0	0	1	0	0	0	0	0	0	0	1997	9146
10609	168	374.0	150054	0	0	0	0	0	1	0	0	0	0	0	0	1997	9228
10614	168	395.9	163115	0	0	0	0	0	1	0	0	0	0	0	0	1997	9260

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10637	168	397.3	165198	0	0	0	0	0	1	0	0	0	0	0	0	1997	9281
10600	168	386.2	154992	0	0	0	0	0	1	0	0	0	0	0	0	1997	9136
10645	168	399.0	164401	0	0	0	0	0	0	1	0	0	0	0	0	1997	9280
10789	86	377.8	151678	0	0	0	0	0	0	1	0	0	0	0	1	1997	9215
10640	168	369.9	140828	0	0	0	0	0	0	1	0	0	0	0	0	1997	8999
10793	168	392.2	155125	0	0	0	0	0	0	1	0	0	0	0	0	1997	9243
10790	168	362.9	137430	0	0	0	0	0	0	0	1	0	0	0	0	1997	9215
10776	135	379.1	148806	0	0	0	0	0	0	0	1	0	0	0	1	1997	9260
10639	168	413.0	170854	0	0	0	0	0	0	0	1	0	0	0	0	1997	9286
10793	123	372.2	148539	0	0	0	0	0	0	0	1	0	0	0	1	1997	9264
10553	168	383.2	152292	0	0	0	0	0	0	0	1	0	0	0	0	1997	9239
10792	131	355.6	137302	0	0	0	0	0	0	0	0	1	0	0	1	1997	9300
10597	168	368.0	142684	0	0	0	0	0	0	0	0	1	0	0	0	1997	9310
10713	139	377.5	148203	0	0	0	0	0	0	0	0	1	0	0	1	1997	9374
10696	168	363.3	138521	0	0	0	0	0	0	0	0	1	0	0	0	1997	9261
10736	24	353.8	133462	0	0	0	0	0	0	0	0	1	0	0	0	1997	9290
10617	168	373.7	143155	0	0	0	0	0	0	0	0	0	1	0	0	1997	9498
10677	83	333.2	112028	0	0	0	0	0	0	0	0	0	1	0	0	1997	9670
10705	68	339.6	127450	0	0	0	0	0	0	0	0	0	1	0	1	1997	9325
10624	146	378.7	151108	0	0	0	0	0	0	0	0	0	1	0	0	1997	9244
10830	167	373.9	148544	0	0	0	0	0	0	0	0	0	0	1	0	1997	9522
10466	124	397.9	166774	0	0	0	0	0	0	0	0	0	0	1	1	1997	9217
10378	168	417.1	177825	0	0	0	0	0	0	0	0	0	0	1	0	1997	9194
10464	153	394.9	164220	0	0	0	0	0	0	0	0	0	0	1	0	1997	9259
10529	168	351.9	134096	0	0	0	0	0	0	0	0	0	0	1	0	1997	9064
10528	168	393.4	159933	0	0	0	0	0	0	0	0	0	0	0	0	1997	9199
10550	168	400.6	164575	0	0	0	0	0	0	0	0	0	0	0	0	1997	9397
10692	100	372.1	144588	0	0	0	0	0	0	0	0	0	0	0	1	1997	9317
10735	168	315.3	110914	0	0	0	0	0	0	0	0	0	0	0	0	1997	9317
10799	168	287.3	94698	1	0	0	0	0	0	0	0	0	0	0	0	1998	9276
10771	168	326.6	115282	1	0	0	0	0	0	0	0	0	0	0	0	1998	9001
10342	168	375.4	147535	1	0	0	0	0	0	0	0	0	0	0	0	1998	9205
10600	168	346.2	126688	1	0	0	0	0	0	0	0	0	0	0	0	1998	9073
10607	168	337.6	122720	1	0	0	0	0	0	0	0	0	0	0	0	1998	9204
10499	72	374.8	146150	0	1	0	0	0	0	0	0	0	0	0	0	1998	9138
10465	128	314.7	111832	0	0	1	0	0	0	0	0	0	0	0	1	1998	9192
10495	168	389.3	163543	0	0	1	0	0	0	0	0	0	0	0	0	1998	9462
10420	167	399.6	171579	0	0	0	1	0	0	0	0	0	0	0	0	1998	9375
10633	105	377.5	158113	0	0	0	1	0	0	0	0	0	0	0	1	1998	9471
10424	137	412.8	180808	0	0	0	1	0	0	0	0	0	0	0	1	1998	9469
10349	168	391.4	166654	0	0	0	1	0	0	0	0	0	0	0	0	1998	9391
10442	168	389.9	161435	0	0	0	0	1	0	0	0	0	0	0	0	1998	9081
10346	168	388.4	160734	0	0	0	0	1	0	0	0	0	0	0	0	1998	9221
10347	168	430.6	190386	0	0	0	0	1	0	0	0	0	0	0	0	1998	9371
10359	168	419.1	182107	0	0	0	0	1	0	0	0	0	0	0	0	1998	9317
10393	168	413.0	179030	0	0	0	0	1	0	0	0	0	0	0	0	1998	9202
10546	168	395.9	168440	0	0	0	0	0	1	0	0	0	0	0	0	1998	9330

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10454	168	419.1	179076	0	0	0	0	0	1	0	0	0	0	0	0	1998	9214
10560	168	386.7	155511	0	0	0	0	0	1	0	0	0	0	0	0	1998	9210
10645	168	378.2	152447	0	0	0	0	0	1	0	0	0	0	0	0	1998	9271
10495	168	395.3	162966	0	0	0	0	0	0	1	0	0	0	0	0	1998	9242
10506	168	387.5	155026	0	0	0	0	0	0	1	0	0	0	0	0	1998	9202
10884	93	319.0	120254	0	0	0	0	0	0	1	0	0	0	0	1	1998	9201
10353	168	419.8	182219	0	0	0	0	0	0	1	0	0	0	0	0	1998	9233
10517	168	414.4	177742	0	0	0	0	0	0	0	1	0	0	0	0	1998	9179
10388	168	418.6	182475	0	0	0	0	0	0	0	1	0	0	0	0	1998	9414
10434	168	399.3	167610	0	0	0	0	0	0	0	1	0	0	0	0	1998	9334
10436	168	431.3	192513	0	0	0	0	0	0	0	1	0	0	0	0	1998	9278
10443	168	450.6	206282	0	0	0	0	0	0	0	1	0	0	0	0	1998	9265
10404	168	436.3	191456	0	0	0	0	0	0	0	0	1	0	0	0	1998	9260
10336	70	426.9	187317	0	0	0	0	0	0	0	0	1	0	0	0	1998	9274
15296	31	106.4	14196	0	0	0	0	0	0	0	0	0	0	0	1	1998	9223
10691	113	321.8	111013	1	0	0	0	0	0	0	0	0	0	0	1	1999	9239
10581	128	356.3	138612	1	0	0	0	0	0	0	0	0	0	0	1	1999	9346
10629	100	357.9	140625	1	0	0	0	0	0	0	0	0	0	0	1	1999	9242
10630	168	395.3	166677	0	1	0	0	0	0	0	0	0	0	0	0	1999	9715
10291	161	304.6	107931	0	1	0	0	0	0	0	0	0	0	0	0	1999	11273
10211	168	386.1	155644	0	1	0	0	0	0	0	0	0	0	0	0	1999	10468
10188	159	390.1	162981	0	1	0	0	0	0	0	0	0	0	0	0	1999	10168
10325	168	362.1	136961	0	0	1	0	0	0	0	0	0	0	0	0	1999	9970
10519	130	431.9	191684	0	0	1	0	0	0	0	0	0	0	0	1	1999	9644
10219	168	450.0	204247	0	0	1	0	0	0	0	0	0	0	0	0	1999	9264
10264	156	435.2	193515	0	0	1	0	0	0	0	0	0	0	0	0	1999	9398
10648	51	392.3	171439	0	0	1	0	0	0	0	0	0	0	0	2	1999	9333
10306	24	441.0	201118	0	0	0	1	0	0	0	0	0	0	0	0	1999	9263
10554	127	329.5	113008	0	0	0	1	0	0	0	0	0	0	0	1	1999	9320
10157	168	457.2	209956	0	0	0	1	0	0	0	0	0	0	0	0	1999	9321
10319	168	451.7	206474	0	0	0	1	0	0	0	0	0	0	0	0	1999	9353
10874	127	356.5	135479	0	0	0	0	1	0	0	0	0	0	0	1	1999	9819
10750	148	387.9	163672	0	0	0	0	1	0	0	0	0	0	0	0	1999	9932
9925	168	388.6	170667	0	0	0	0	1	0	0	0	0	0	0	0	1999	11148
10369	150	409.5	184361	0	0	0	0	1	0	0	0	0	0	0	0	1999	11325
10681	168	366.8	153244	0	0	0	0	1	0	0	0	0	0	0	0	1999	11256
10087	168	417.5	187770	0	0	0	0	0	1	0	0	0	0	0	0	1999	11009
9819	168	427.1	193747	0	0	0	0	0	1	0	0	0	0	0	0	1999	10644
9997	168	417.3	189676	0	0	0	0	0	1	0	0	0	0	0	0	1999	10698
9617	144	439.4	200007	0	0	0	0	0	1	0	0	0	0	0	0	1999	10207

Data Base for DANIEL 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
BTU/LB	Average heat content of coal burned by the unit for the week.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10346	168	316.5	124968	0	0	0	0	0	0	1	0	0	0	0	0	1996	11217
10521	154	328.9	136965	0	0	0	0	0	0	1	0	0	0	0	0	1996	11094
10282	168	366.9	156999	0	0	0	0	0	0	1	0	0	0	0	0	1996	11203
10383	168	339.0	139593	0	0	0	0	0	0	1	0	0	0	0	0	1996	11319
10351	168	336.3	138413	0	0	0	0	0	0	0	1	0	0	0	0	1996	11466
10302	168	330.7	136177	0	0	0	0	0	0	0	1	0	0	0	0	1996	11301
10374	168	335.0	139983	0	0	0	0	0	0	0	1	0	0	0	0	1996	11138
10510	138	293.6	108165	0	0	0	0	0	0	0	1	0	0	0	1	1996	11103
10779	168	254.7	83904	0	0	0	0	0	0	0	1	0	0	0	0	1996	11115
10679	168	295.7	109065	0	0	0	0	0	0	0	0	1	0	0	0	1996	11131
10824	168	368.9	151722	0	0	0	0	0	0	0	0	1	0	0	0	1996	9452
10643	168	406.4	174961	0	0	0	0	0	0	0	0	1	0	0	0	1996	9271
10672	168	386.8	160741	0	0	0	0	0	0	0	0	1	0	0	0	1996	9400
10504	24	400.9	170256	0	0	0	0	0	0	0	0	1	0	0	0	1996	9274
10131	168	422.2	183607	0	0	0	0	0	0	0	0	0	1	0	0	1996	9072
10387	168	398.5	169036	0	0	0	0	0	0	0	0	0	1	0	0	1996	9329
10451	168	421.1	184735	0	0	0	0	0	0	0	0	0	1	0	0	1996	9341
10395	169	424.7	187212	0	0	0	0	0	0	0	0	0	1	0	0	1996	9313
10499	168	406.6	173305	0	0	0	0	0	0	0	0	0	0	1	0	1996	9313
10636	168	384.5	152482	0	0	0	0	0	0	0	0	0	0	1	0	1996	9342
10243	74	413.9	179535	0	0	0	0	0	0	0	0	0	0	1	0	1996	9308
10253	106	385.8	160769	0	0	0	0	0	0	0	0	0	0	1	1	1996	9326
10340	168	401.2	168261	0	0	0	0	0	0	0	0	0	0	1	0	1996	9404
10345	168	460.7	215927	0	0	0	0	0	0	0	0	0	0	0	0	1996	9493
10367	168	415.4	180617	0	0	0	0	0	0	0	0	0	0	0	0	1996	9338
10178	168	442.7	201239	0	0	0	0	0	0	0	0	0	0	0	0	1996	9356
10338	168	375.5	152947	0	0	0	0	0	0	0	0	0	0	0	0	1996	9259
10324	168	411.2	175882	1	0	0	0	0	0	0	0	0	0	0	0	1997	9376
10222	168	457.6	209533	1	0	0	0	0	0	0	0	0	0	0	0	1997	9323
9840	120	435.2	194714	1	0	0	0	0	0	0	0	0	0	0	0	1997	9230
13137	59	189.0	49912	0	1	0	0	0	0	0	0	0	0	0	2	1997	9236
10459	166	387.2	160496	0	1	0	0	0	0	0	0	0	0	0	0	1997	9248
10134	168	405.1	173947	0	1	0	0	0	0	0	0	0	0	0	0	1997	9121
10109	168	398.7	170639	0	0	1	0	0	0	0	0	0	0	0	0	1997	9369
10212	168	411.3	179282	0	0	1	0	0	0	0	0	0	0	0	0	1997	9235
10125	168	432.4	192365	0	0	1	0	0	0	0	0	0	0	0	0	1997	9200
10257	168	451.0	205440	0	0	1	0	0	0	0	0	0	0	0	0	1997	9259
10211	167	460.7	214256	0	0	0	1	0	0	0	0	0	0	0	0	1997	9280
10513	167	377.6	160881	0	0	0	1	0	0	0	0	0	0	0	0	1997	9204
10163	168	459.4	211500	0	0	0	1	0	0	0	0	0	0	0	0	1997	9227
10215	96	425.5	183397	0	0	0	1	0	0	0	0	0	0	0	0	1997	10430
10736	29	317.5	116301	0	0	0	0	1	0	0	0	0	0	0	1	1997	9448
10397	157	400.3	168885	0	0	0	0	1	0	0	0	0	0	0	0	1997	9471
10284	110	418.3	181814	0	0	0	0	1	0	0	0	0	0	0	1	1997	9477
10406	157	441.3	200684	0	0	0	0	1	0	0	0	0	0	0	0	1997	9489
10293	165	422.5	188920	0	0	0	0	1	0	0	0	0	0	0	0	1997	9149
10239	168	403.6	172114	0	0	0	0	0	1	0	0	0	0	0	0	1997	9229

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10346	168	425.3	187103	0	0	0	0	0	1	0	0	0	0	0	0	1997	9260
10367	168	430.0	190572	0	0	0	0	0	1	0	0	0	0	0	0	1997	9282
10365	168	421.7	181660	0	0	0	0	0	1	0	0	0	0	0	0	1997	9136
10349	91	420.8	183395	0	0	0	0	0	0	1	0	0	0	0	0	1997	9268
10312	166	434.5	194546	0	0	0	0	0	0	1	0	0	0	0	1	1997	9240
10313	168	411.7	172947	0	0	0	0	0	0	1	0	0	0	0	0	1997	8996
10480	168	424.5	181953	0	0	0	0	0	0	1	0	0	0	0	0	1997	9243
10453	168	411.2	176328	0	0	0	0	0	0	0	1	0	0	0	0	1997	9217
10361	168	427.4	186660	0	0	0	0	0	0	0	1	0	0	0	0	1997	9266
10399	168	463.1	214743	0	0	0	0	0	0	0	1	0	0	0	0	1997	9286
10363	168	440.8	199395	0	0	0	0	0	0	0	1	0	0	0	0	1997	9263
10373	168	426.4	187242	0	0	0	0	0	0	0	1	0	0	0	0	1997	9243
10397	168	400.8	170577	0	0	0	0	0	0	0	0	1	0	0	0	1997	9299
10345	168	421.1	183222	0	0	0	0	0	0	0	0	1	0	0	0	1997	9310
10359	168	450.0	203364	0	0	0	0	0	0	0	0	1	0	0	0	1997	9382
10315	168	429.3	188643	0	0	0	0	0	0	0	0	1	0	0	0	1997	9261
10263	24	417.8	180295	0	0	0	0	0	0	0	0	1	0	0	0	1997	9290
10019	41	394.4	161330	0	0	0	0	0	0	0	0	0	1	0	0	1997	10369
9942	89	434.7	194442	0	0	0	0	0	0	0	0	0	1	0	1	1997	9208
10188	131	395.4	169441	0	0	0	0	0	0	0	0	0	1	0	1	1997	9324
10071	169	446.0	203560	0	0	0	0	0	0	0	0	0	1	0	0	1997	9248
10504	113	436.2	196652	0	0	0	0	0	0	0	0	0	0	1	1	1997	9600
10024	168	427.8	187364	0	0	0	0	0	0	0	0	0	0	1	0	1997	9227
10196	168	400.4	162773	0	0	0	0	0	0	0	0	0	0	1	0	1997	9187
10198	168	462.1	214160	0	0	0	0	0	0	0	0	0	0	1	0	1997	9267
10212	168	435.5	191599	0	0	0	0	0	0	0	0	0	0	1	0	1997	9060
10235	168	451.6	205337	0	0	0	0	0	0	0	0	0	0	0	0	1997	9198
10188	168	456.8	209735	0	0	0	0	0	0	0	0	0	0	0	0	1997	9396
10088	168	445.5	200240	0	0	0	0	0	0	0	0	0	0	0	0	1997	9334
10245	168	364.8	143680	0	0	0	0	0	0	0	0	0	0	0	0	1997	9313
10048	168	396.4	158780	1	0	0	0	0	0	0	0	0	0	0	0	1998	9286
10252	168	405.1	164789	1	0	0	0	0	0	0	0	0	0	0	0	1998	9002
9909	73	390.5	155669	1	0	0	0	0	0	0	0	0	0	0	0	1998	9025
10314	139	393.6	165512	1	0	0	0	0	0	0	0	0	0	0	1	1998	9097
10148	168	445.2	200722	1	0	0	0	0	0	0	0	0	0	0	0	1998	9202
10120	168	442.4	197540	0	1	0	0	0	0	0	0	0	0	0	0	1998	9218
10217	168	415.6	179355	0	1	0	0	0	0	0	0	0	0	0	0	1998	9306
10148	168	413.6	177315	0	1	0	0	0	0	0	0	0	0	0	0	1998	9238
10088	168	389.3	156584	0	1	0	0	0	0	0	0	0	0	0	0	1998	9278
10119	168	409.2	171606	0	0	1	0	0	0	0	0	0	0	0	0	1998	9244
10290	168	434.4	194187	0	0	1	0	0	0	0	0	0	0	0	0	1998	9163
10132	168	405.1	169019	0	0	1	0	0	0	0	0	0	0	0	0	1998	9210
10453	72	351.2	124232	0	0	1	0	0	0	0	0	0	0	0	0	1998	9430
10269	114	400.8	168990	0	0	0	1	0	0	0	0	0	0	0	1	1998	9524
10125	168	436.4	194730	0	0	0	1	0	0	0	0	0	0	0	0	1998	9442
10138	168	395.7	158239	0	0	0	1	0	0	0	0	0	0	0	0	1998	9394
10213	168	390.7	153419	0	0	0	0	1	0	0	0	0	0	0	0	1998	9085

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10158	148	393.3	159343	0	0	0	0	1	0	0	0	0	0	0	0	1998	9215
10184	168	430.4	186464	0	0	0	0	1	0	0	0	0	0	0	0	1998	9370
10224	168	435.2	189543	0	0	0	0	1	0	0	0	0	0	0	0	1998	9316
10305	168	432.0	187895	0	0	0	0	1	0	0	0	0	0	0	0	1998	9204
10425	87	399.8	167702	0	0	0	0	0	1	0	0	0	0	0	0	1998	9292
10342	165	421.7	181454	0	0	0	0	0	1	0	0	0	0	0	1	1998	9214
10349	168	427.7	182916	0	0	0	0	0	1	0	0	0	0	0	0	1998	9211
10410	168	426.1	181563	0	0	0	0	0	1	0	0	0	0	0	0	1998	9273
10438	168	423.3	181757	0	0	0	0	0	0	1	0	0	0	0	0	1998	9240
10452	168	427.4	182908	0	0	0	0	0	0	1	0	0	0	0	0	1998	9195
10608	168	409.2	167847	0	0	0	0	0	0	1	0	0	0	0	0	1998	9248
10556	168	414.6	171942	0	0	0	0	0	0	1	0	0	0	0	0	1998	9231
10866	108	387.2	155449	0	0	0	0	0	0	0	1	0	0	0	1	1998	9131
10491	168	420.9	177529	0	0	0	0	0	0	0	1	0	0	0	0	1998	9416
10480	168	420.9	178419	0	0	0	0	0	0	0	1	0	0	0	0	1998	9334
10600	130	402.7	168249	0	0	0	0	0	0	0	1	0	0	0	1	1998	9270
10567	168	408.1	167617	0	0	0	0	0	0	0	1	0	0	0	0	1998	9264
10531	90	390.8	158478	0	0	0	0	0	0	0	0	1	0	0	1	1998	9240
10440	168	395.3	160731	0	0	0	0	0	0	0	0	1	0	0	0	1998	9115
10511	168	405.4	164564	0	0	0	0	0	0	0	0	1	0	0	0	1998	9056
10536	139	394.9	158357	0	0	0	0	0	0	0	0	1	0	0	0	1998	9071
10518	123	396.4	159575	0	0	0	0	0	0	0	0	0	1	0	1	1998	9097
10551	137	371.1	142962	0	0	0	0	0	0	0	0	0	1	0	1	1998	8964
10572	140	362.8	139324	0	0	0	0	0	0	0	0	0	1	0	1	1998	9358
10413	124	343.5	125942	0	0	0	0	0	0	0	0	0	1	0	1	1998	9290
10645	168	317.4	110032	0	0	0	0	0	0	0	0	0	0	1	0	1998	9361
10438	49	335.9	120644	0	0	0	0	0	0	0	0	0	0	1	0	1998	9389
11007	67	275.3	77553	0	0	0	0	0	0	0	0	0	0	1	1	1998	9113
10555	168	296.0	89935	0	0	0	0	0	0	0	0	0	0	0	0	1998	9177
10304	163	359.7	131387	0	0	0	0	0	0	0	0	0	0	0	0	1998	9189
10730	110	304.6	99675	0	0	0	0	0	0	0	0	0	0	0	1	1998	9192
10355	168	347.0	121339	0	0	0	0	0	0	0	0	0	0	0	0	1998	9261
10352	24	359.1	129028	0	0	0	0	1	0	0	0	0	0	0	0	1998	9353
10406	168	357.0	128039	1	0	0	0	0	0	0	0	0	0	0	0	1999	9257
10549	168	330.6	112360	1	0	0	0	0	0	0	0	0	0	0	0	1999	9222
10617	168	320.2	105824	1	0	0	0	0	0	0	0	0	0	0	0	1999	9357
10889	128	296.9	93406	1	0	0	0	0	0	0	0	0	0	0	1	1999	9238
10699	168	334.9	112730	0	1	0	0	0	0	0	0	0	0	0	0	1999	9242
11053	22	326.9	110789	0	1	0	0	0	0	0	0	0	0	0	0	1999	9843
* 19150	25	157.4	30819	0	0	0	1	0	0	0	0	0	0	0	1	1999	9413
9934	150	330.4	119199	0	0	0	1	0	0	0	0	0	0	0	1	1999	9341
9932	168	466.4	222080	0	0	0	0	1	0	0	0	0	0	0	0	1999	10168
9437	168	434.9	201923	0	0	0	0	1	0	0	0	0	0	0	0	1999	10765
10317	168	406.1	183509	0	0	0	0	1	0	0	0	0	0	0	0	1999	11341
10392	123	396.7	175868	0	0	0	0	1	0	0	0	0	0	0	1	1999	11367
10478	168	405.9	182081	0	0	0	0	1	0	0	0	0	0	0	0	1999	11262
10115	168	413.4	186080	0	0	0	0	0	1	0	0	0	0	0	0	1999	11006

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR	BTU/LB
10033	157	390.1	169872	0	0	0	0	0	1	0	0	0	0	0	0	1999	10642
9966	168	407.2	183960	0	0	0	0	0	1	0	0	0	0	0	0	1999	10698
9563	144	435.9	198496	0	0	0	0	0	1	0	0	0	0	0	0	1999	10209

Data Base for DANIEL 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
BTU/LB	Average heat content of coal burned by the unit for the week.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2000 - December 2000

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 6	Jan '00	232.6	59,489	10,667	75,590	
	Feb '00	239.1	62,439	10,656	16,740	
	Mar '00	252.5	68,638	10,637	170,190	
	Apr '00	244.0	64,687	10,465	158,340	
	May '00	229.2	57,961	10,563	165,050	
	Jun '00	252.7	68,732	10,636	176,160	
	Jul '00	251.9	68,357	10,637	181,350	
	Aug '00	260.9	72,604	10,625	187,870	
	Sep '00	237.7	61,801	10,658	165,710	
	Oct '00	233.8	60,031	10,665	168,540	
	Nov '00	223.8	55,555	10,682	155,990	
	Dec '00	213.0	50,819	10,702	153,380	10,629
CRIST 7	Jan '00	420.8	187,475	10,238	287,810	
	Feb '00	428.4	192,857	10,229	236,500	
	Mar '00	0.0	0	-	0	
	Apr '00	433.4	196,408	10,223	143,030	
	May '00	415.1	183,451	10,377	283,920	
	Jun '00	456.5	212,923	10,198	302,170	
	Jul '00	452.8	210,266	10,202	309,690	
	Aug '00	463.5	217,962	10,191	317,060	
	Sep '00	426.4	191,439	10,231	263,500	
	Oct '00	426.8	191,722	10,231	273,560	
	Nov '00	439.3	200,609	10,216	271,500	
	Dec '00	403.8	175,507	10,259	258,420	10,236
SMITH 1	Jan '00	106.5	12,865	10,456	77,730	
	Feb '00	119.6	15,842	10,341	36,610	
	Mar '00	127.2	17,589	10,288	92,820	
	Apr '00	123.6	16,760	10,202	78,510	
	May '00	109.8	13,611	10,287	80,190	
	Jun '00	126.6	17,451	10,292	89,520	
	Jul '00	127.5	17,658	10,383	93,110	
	Aug '00	131.2	18,514	10,263	95,770	
	Sep '00	117.2	15,294	10,360	82,840	
	Oct '00	118.2	15,522	10,352	86,390	
	Nov '00	114.5	14,678	10,243	56,690	
	Dec '00	100.1	11,426	10,526	73,070	10,332

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2000 - December 2000

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast BTU/LB	(4) Forecast Monthly ANOHR	(5) Forecast AKW * 10^3 Generation	(6) Weighted ANOHR Target
SMITH 2	Jan '00	146.8	23,830	-	10,117	105,810	
	Feb '00	156.4	26,391	-	10,081	105,540	
	Mar '00	166.1	29,015	-	10,048	119,780	
	Apr '00	160.2	27,415	-	10,068	104,120	
	May '00	148.4	24,254	-	10,255	51,780	
	Jun '00	166.3	29,069	-	10,147	116,100	
	Jul '00	165.4	28,824	-	10,249	119,230	
	Aug '00	172.4	30,738	-	10,209	124,300	
	Sep '00	150.3	24,760	-	10,182	104,890	
	Oct '00	154.2	25,801	-	10,089	111,330	
	Nov '00	156.7	26,472	-	10,080	87,460	
	Dec '00	137.1	21,278	-	10,159	82,970	10,137
DANIEL 1	Jan '00	436.6	195,007	9,758	10,246	301,670	
	Feb '00	445.9	202,157	9,767	10,312	248,390	
	Mar '00	0.0	0	9,730	-	0	
	Apr '00	441.8	198,992	10,057	10,275	206,780	
	May '00	375.2	150,540	10,326	10,418	259,270	
	Jun '00	425.1	186,317	10,550	10,128	284,410	
	Jul '00	424.3	185,718	10,735	10,203	293,170	
	Aug '00	447.4	203,321	10,889	10,125	309,160	
	Sep '00	391.6	161,952	11,013	10,238	261,990	
	Oct '00	415.1	178,895	11,101	10,162	139,070	
	Nov '00	402.3	169,580	11,151	10,184	188,290	
	Dec '00	354.1	136,357	11,188	10,315	244,710	10,237
DANIEL 2	Jan '00	454.0	208,362	9,758	10,013	194,770	
	Feb '00	454.9	209,082	9,767	10,093	256,560	
	Mar '00	461.6	214,482	9,730	10,082	177,250	
	Apr '00	449.9	205,096	10,057	10,069	283,880	
	May '00	390.8	160,828	10,326	10,184	273,530	
	Jun '00	441.2	198,250	10,550	10,027	298,720	
	Jul '00	438.3	195,994	10,735	10,169	306,830	
	Aug '00	462.1	214,888	10,889	10,113	323,460	
	Sep '00	406.0	171,712	11,013	10,237	201,760	
	Oct '00	0.0	0	11,101	-	0	
	Nov '00	407.4	172,732	11,151	10,026	229,790	
	Dec '00	367.3	144,683	11,188	10,127	257,100	10,105

NOTE: Column (4) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (6) $(\Sigma ((4)*(5)))/(\Sigma (5))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2000 - December 2000

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 6	10,629	10,310	10,948
CRIST 7	10,236	9,929	10,543
SMITH 1	10,332	10,022	10,642
SMITH 2	10,137	9,833	10,441
DANIEL 1	10,237	9,930	10,544
DANIEL 2	10,105	9,802	10,408

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2000 - December 2000

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '00 - Dec '00	Reserve Shutdown Hours for Jan '00 - Dec '00	Target Equivalent Availability **
Crist 6	0.0447	1,032	0	84.3
Crist 7	0.1044	1,200	0	77.3
Smith 1	0.0277	600	0	90.6
Smith 2	0.0370	648	0	89.2
Daniel 1	0.1192	1,271	0	75.3
Daniel 2	0.1094	1,440	0	74.5

* For Period July 1994 Through June 1999.

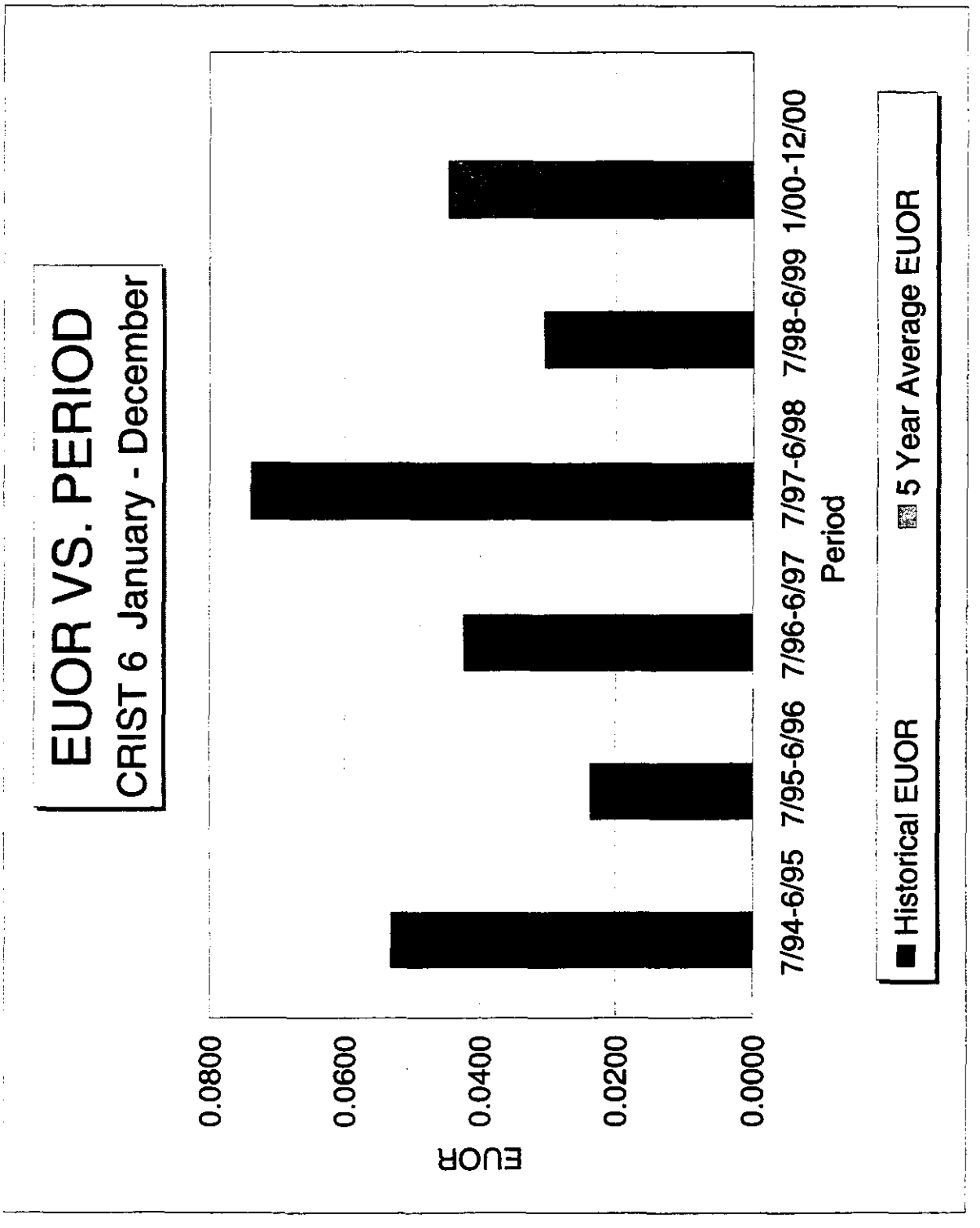
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

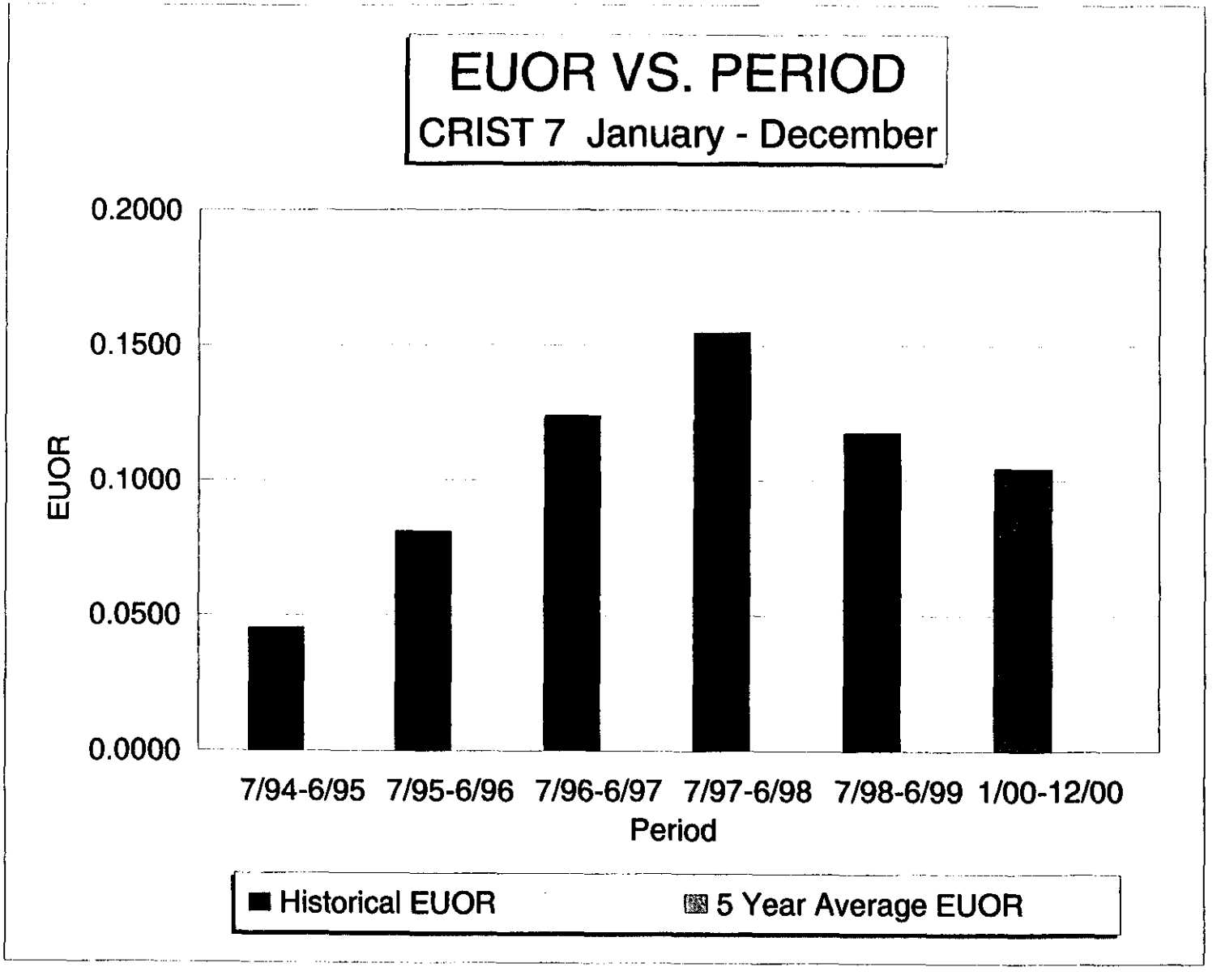
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2000 - December 2000

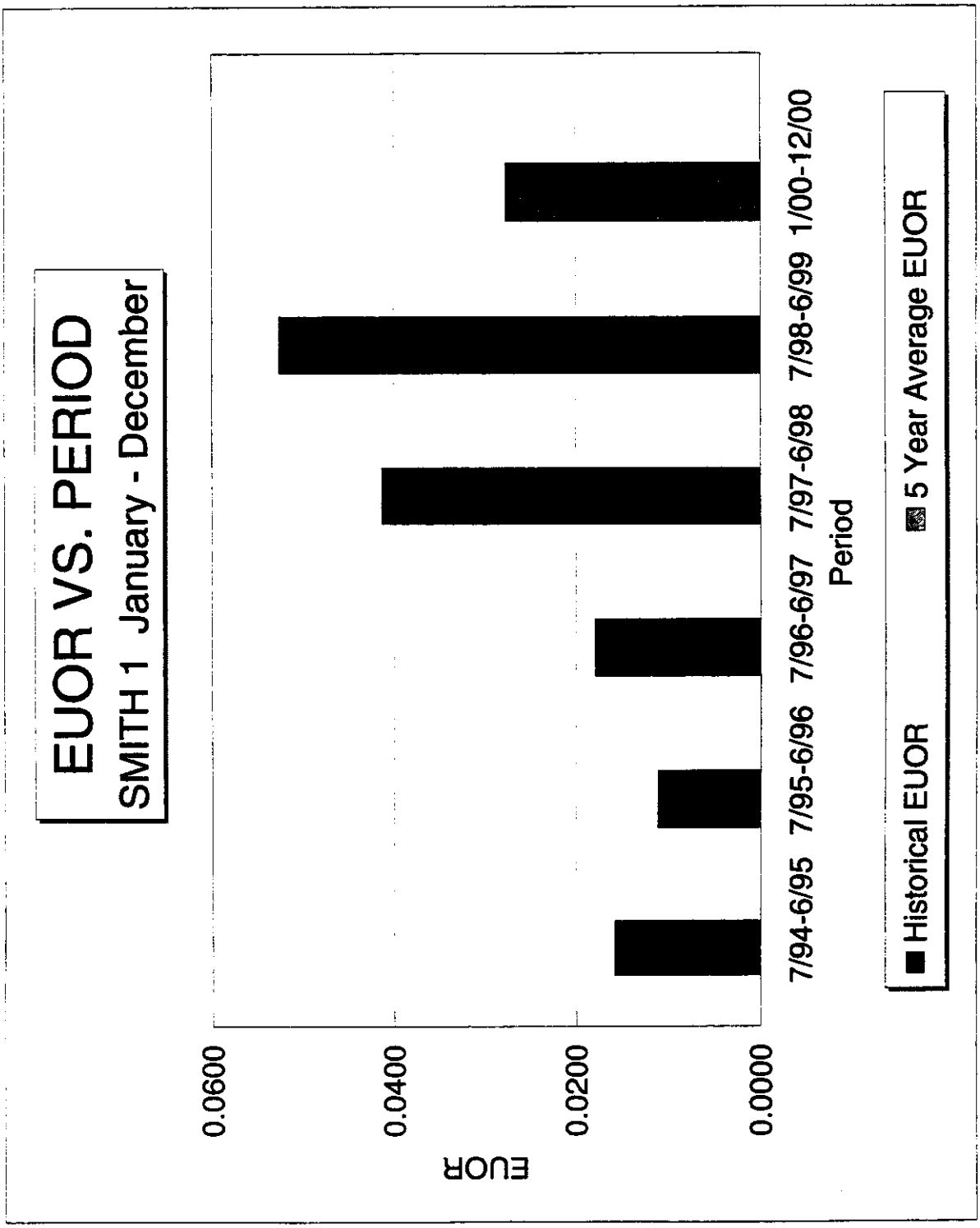
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 6	0.0447	0.0313	85.5	0.0648	82.5
Crist 7	0.1044	0.0731	80.0	0.1514	73.3
Smith 1	0.0277	0.0194	91.4	0.0402	89.4
Smith 2	0.0370	0.0259	90.2	0.0537	87.6
Daniel 1	0.1192	0.0834	78.4	0.1728	70.8
Daniel 2	0.1094	0.0766	77.2	0.1586	70.3

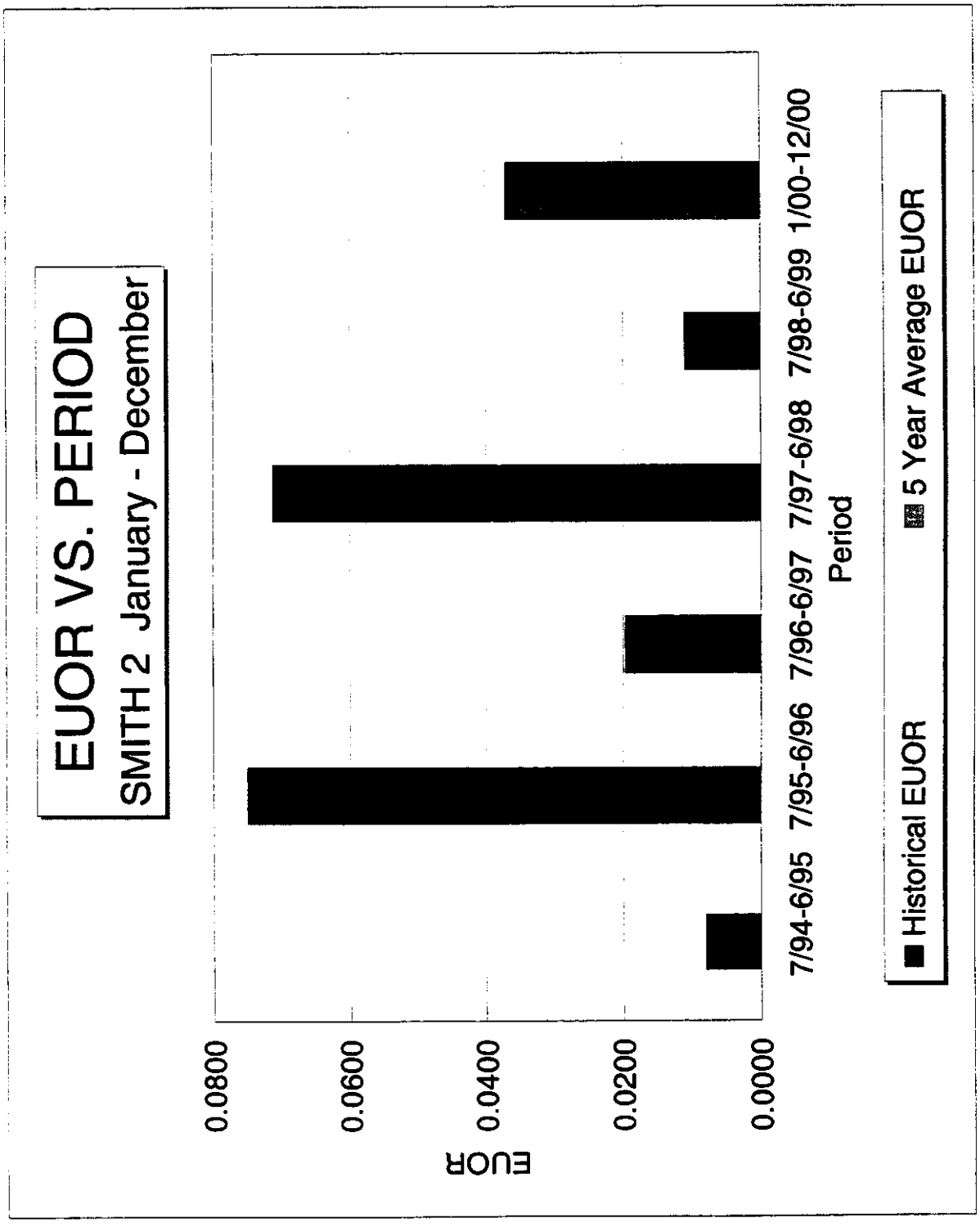
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2000 - December 2000

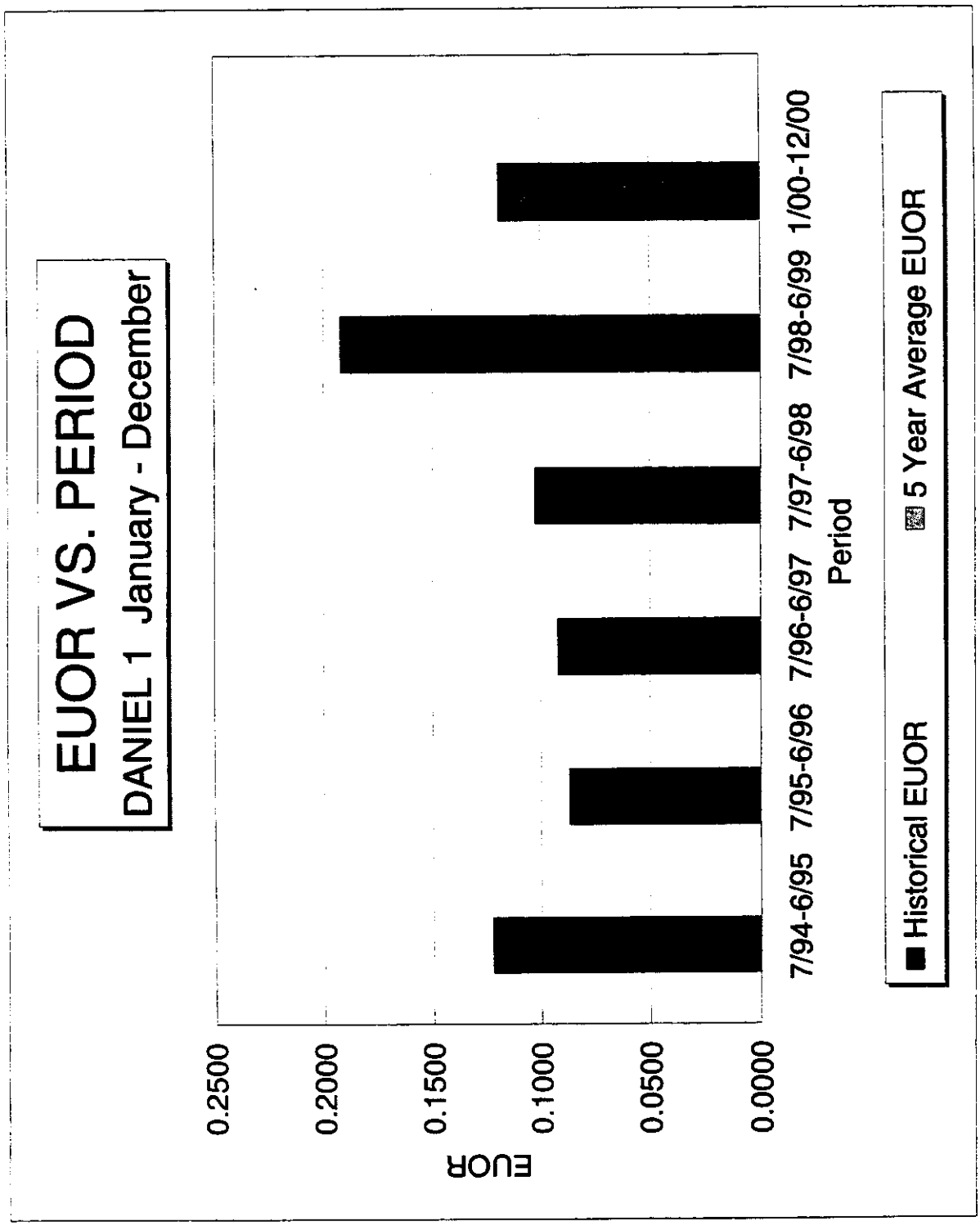
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 6	84.3	85.5	82.5
Crist 7	77.3	80.0	73.3
Smith 1	90.6	91.4	89.4
Smith 2	89.2	90.2	87.6
Daniel 1	75.3	78.4	70.8
Daniel 2	74.5	77.2	70.3

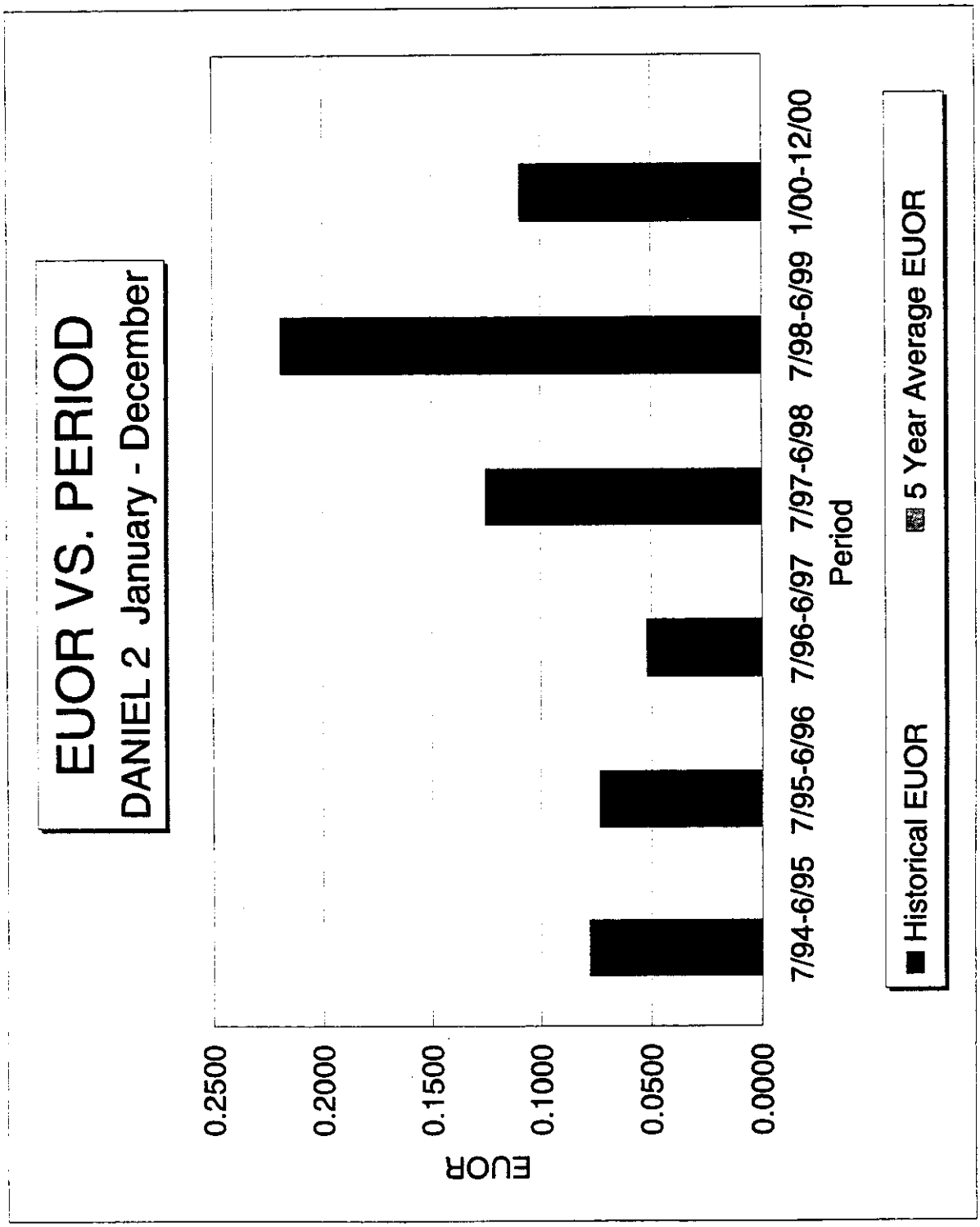

EUOR VS. PERIOD
CRIST 6 January - December
EUOR
0.0800
0.0600
0.0400
0.0200
0.0000
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January - December
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January - December
EUOR
0.0600
0.0400
0.0200
0.0000
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January - December
EUOR
0.0800
0.0600
0.0400
0.0200
0.0000
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January - December
EUOR
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January - December
EUOR
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
7/94-6/95
7/95-6/96
7/96-6/97
7/97-6/98
7/98-6/99
1/00-12/00
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

CONTENTS

	SCHEDULE 3 PAGE
GPIF Reward/Penalty Table (Estimated)	3
GPIF Calculation of Maximum Allowed Incentive Dollars	4
GPIF Target and Range Summary	5
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for Availability	6 - 7
Comparison of GPIF Targets vs. Prior Seasons' Actual Performance for ANOHR	8
Example Calculation of Prior Season ANOHR	9
Derivation of Weighting Factors	10
GPIF Unit Point Tables	11 - 16
Estimated Unit Performance Data	17 - 29
Planned Outage Schedules	30 - 31

Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2000 - December 2000

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	6941	1668
+ 9	6247	1501
+ 8	5553	1334
+ 7	4859	1168
+ 6	4165	1001
+ 5	3471	834
+ 4	2776	667
+ 3	2082	500
+ 2	1388	334
+ 1	694	167
0	0	0
- 1	-795	-167
- 2	-1590	-334
- 3	-2385	-500
- 4	-3180	-667
- 5	-3975	-834
- 6	-4769	-1001
- 7	-5564	-1168
- 8	-6359	-1334
- 9	-7154	-1501
- 10	-7949	-1668
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

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Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2000 - December 2000

Line 1	Beginning of Period Balance of Common Equity	$417,899,000
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '00	$422,647,000
Line 3	Month of Feb '00	$410,974,000
Line 4	Month of Mar '00	$413,609,000
Line 5	Month of Apr '00	$401,238,000
Line 6	Month of May '00	$405,332,000
Line 7	Month of Jun '00	$413,777,000
Line 8	Month of Jul '00	$416,170,000
Line 9	Month of Aug '00	$426,115,000
Line 10	Month of Sep '00	$432,947,000
Line 11	Month of Oct '00	$421,459,000
Line 12	Month of Nov '00	$423,444,000
Line 13	Month of Dec '00	$428,024,000
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$417,971,923
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	60.4594%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$1,728,317
Line 18	Jurisdictional Sales (KWH)	9,993,721,000
Line 19	Total Territorial Sales (KWH)	10,354,345,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.5172%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$1,668,123

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 6	1.9%	84.3	85.5	82.5	$132	($182)
Crist 7	8.8%	77.3	80.0	73.3	$614	($876)
Smith 1	0.5%	90.6	91.4	89.4	$38	($45)
Smith 2	1.2%	89.2	90.2	87.6	$81	($133)
Daniel 1	7.8%	75.3	78.4	70.8	$539	($875)
Daniel 2	6.5%	74.5	77.2	70.3	$454	($755)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 6	12.1%	10,629	79.3	10,310	10,948	$843	($843)
Crist 7	17.3%	10,236	93.2	9,929	10,543	$1,204	($1,204)
Smith 1	4.1%	10,332	73.1	10,022	10,642	$284	($284)
Smith 2	5.3%	10,137	81.5	9,833	10,441	$369	($369)
Daniel 1	16.7%	10,237	82.3	9,930	10,544	$1,156	($1,156)
Daniel 2	17.7%	10,105	85.3	9,802	10,408	$1,227	($1,227)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '98 - Jun '99			Actual Performance 2nd Prior Period Jul '97 - Jun '98		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 6	1.9%	7.1%	0.1175	0.0395	0.0447	0.0768	0.0281	0.0305	0.1549	0.0593	0.0739
Crist 7	8.8%	33.0%	0.1366	0.0902	0.1044	0.0888	0.1072	0.1177	0.0721	0.1426	0.1545
Smith 1	0.5%	2.0%	0.0683	0.0258	0.0277	0.2058	0.0417	0.0526	0.0468	0.0394	0.0413
Smith 2	1.2%	4.4%	0.0738	0.0343	0.0370	0.0583	0.0103	0.0110	0.2248	0.0547	0.0713
Daniel 1	7.8%	29.0%	0.1447	0.1019	0.1192	0.2959	0.1352	0.1920	0.1325	0.0889	0.1025
Daniel 2	6.5%	24.4%	0.1639	0.0914	0.1094	0.2633	0.1614	0.2191	0.0235	0.1221	0.1251
Weighted GPIF System Average:			0.1401	0.0865	0.1012	0.1917	0.1174	0.1519	0.0898	0.1102	0.1206

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '96 - Jun '97			Actual Performance 4th Prior Period Jul '95 - Jun '96			Actual Performance 5th Prior Period Jul '94 - Jun '95		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 6	1.9%	7.1%	0.0273	0.0363	0.0424	0.1183	0.0176	0.0236	0.1183	0.0176	0.0236
Crist 7	8.8%	33.0%	0.1595	0.0985	0.1238	0.3446	0.0518	0.0809	0.3446	0.0518	0.0809
Smith 1	0.5%	2.0%	0.0647	0.0165	0.0179	0.0602	0.0105	0.0111	0.0602	0.0105	0.0111
Smith 2	1.2%	4.4%	0.0669	0.0181	0.0197	0.0580	0.0702	0.0750	0.0580	0.0702	0.0750
Daniel 1	7.8%	29.0%	0.1143	0.0817	0.0922	0.2291	0.0649	0.0869	0.2291	0.0649	0.0869
Daniel 2	6.5%	24.4%	0.0995	0.0468	0.0519	0.2586	0.0532	0.0731	0.2586	0.0532	0.0731
Weighted GPIF System Average:			0.1164	0.0714	0.0846	0.2557	0.0535	0.0750	0.2557	0.0535	0.0750

Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '98 - Jun '99	2nd Prior Period Heat Rate Jul '97 - Jun '98	3rd Prior Period Heat Rate Jul '96 - Jun '97
Crist 6	12.1%	16.6%	10,629	10,608	10,630	10,561
Crist 7	17.3%	23.7%	10,236	10,207	10,259	10,269
Smith 1	4.1%	5.6%	10,332	10,238	10,399	10,304
Smith 2	5.3%	7.3%	10,137	10,075	10,113	10,219
Daniel 1	16.7%	22.7%	10,237	10,179	10,227	10,319
Daniel 2	17.7%	24.1%	10,105	10,139	10,061	10,139
Weighted GPIF System Average:			10,268	10,243	10,263	10,296

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '97 - Jun '98

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun	
1. Target Heat Rate*	10637 10667	10625 10656	10658 10637	10665 10465	10682 10563	10702 10636	
2. Target Heat Rate at Actual Conditions**	10764 10709	10733 10737	10712 10677	10731 10485	0 10552	10746 10651	
3. Adjustments to Actual Heat Rate (1-2)	-127 -42	-108 -81	-54 -40	-66 -20	10682 11	-44 -15	
4. Actual Heat Rate for Prior Period	11060 10927	10693 10603	10537 10591	10547 10568	0 10452	10967 10567	
5. Adjusted actual Heat Rate (4+3)	10933 10885	10585 10522	10483 10551	10481 10548	10682 10463	10923 10552	
6. Forecast Net MWH Generation*	181350 75590	187870 16740	165710 170190	168540 158340	155990 165050	153380 176160	
7. Adjusted Actual Heat Rate for Jul '97 - Jun '98 = (Σ ((5) * (6)))/(Σ (6))							10,630

* For the January 2000 - December 2000 time period.

** Based on the target heat rate equation from page 2 of Schedule 1 using actual rather than forecast variable values.

Derivation of Weighting Factors

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 6	EA-1	$193,461	$193,329	$132	1.9%
Crist 6	ANOHR-1	$193,461	$192,618	$843	12.1%
Crist 7	EA-2	$193,461	$192,847	$614	8.8%
Crist 7	ANOHR-2	$193,461	$192,257	$1,204	17.3%
Smith 1	EA-3	$193,461	$193,423	$38	0.5%
Smith 1	ANOHR-3	$193,461	$193,177	$284	4.1%
Smith 2	EA-4	$193,461	$193,380	$81	1.2%
Smith 2	ANOHR-4	$193,461	$193,092	$369	5.3%
Daniel 1	EA-5	$193,461	$192,922	$539	7.8%
Daniel 1	ANOHR-5	$193,461	$192,305	$1,156	16.7%
Daniel 2	EA-6	$193,461	$193,007	$454	6.5%
Daniel 2	ANOHR-6	$193,461	$192,234	$1,227	17.7%
					100.0%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	132	85.50	+ 10	843	10,310
+ 9	119	85.38	+ 9	759	10,334
+ 8	106	85.26	+ 8	674	10,359
+ 7	92	85.14	+ 7	590	10,383
+ 6	79	85.02	+ 6	506	10,408
+ 5	66	84.90	+ 5	422	10,432
+ 4	53	84.78	+ 4	337	10,456
+ 3	40	84.66	+ 3	253	10,481
+ 2	26	84.54	+ 2	169	10,505
+ 1	13	84.42	+ 1	84	10,530
				0	10,554
0	0	84.30	0	0	10,629
				0	10,704
- 1	(18)	84.12	- 1	(84)	10,728
- 2	(36)	83.94	- 2	(169)	10,753
- 3	(55)	83.76	- 3	(253)	10,777
- 4	(73)	83.58	- 4	(337)	10,802
- 5	(91)	83.40	- 5	(422)	10,826
- 6	(109)	83.22	- 6	(506)	10,850
- 7	(127)	83.04	- 7	(590)	10,875
- 8	(146)	82.86	- 8	(674)	10,899
- 9	(164)	82.68	- 9	(759)	10,924
- 10	(182)	82.50	- 10	(843)	10,948
Weighting Factor:		0.019	Weighting Factor:		0.121

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	614	80.00	+ 10	1,204	9,929
+ 9	553	79.73	+ 9	1,084	9,952
+ 8	491	79.46	+ 8	963	9,975
+ 7	430	79.19	+ 7	843	9,999
+ 6	368	78.92	+ 6	722	10,022
+ 5	307	78.65	+ 5	602	10,045
+ 4	246	78.38	+ 4	482	10,068
+ 3	184	78.11	+ 3	361	10,091
+ 2	123	77.84	+ 2	241	10,115
+ 1	61	77.57	+ 1	120	10,138
				0	10,161
0	0	77.30	0	0	10,236
				0	10,311
- 1	(88)	76.90	- 1	(120)	10,334
- 2	(175)	76.50	- 2	(241)	10,357
- 3	(263)	76.10	- 3	(361)	10,381
- 4	(350)	75.70	- 4	(482)	10,404
- 5	(438)	75.30	- 5	(602)	10,427
- 6	(526)	74.90	- 6	(722)	10,450
- 7	(613)	74.50	- 7	(843)	10,473
- 8	(701)	74.10	- 8	(963)	10,497
- 9	(788)	73.70	- 9	(1,084)	10,520
- 10	(876)	73.30	- 10	(1,204)	10,543
Weighting Factor:		0.088	Weighting Factor:		0.173

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	38	91.40	+ 10	284	10,022
+ 9	34	91.32	+ 9	256	10,046
+ 8	30	91.24	+ 8	227	10,069
+ 7	27	91.16	+ 7	199	10,093
+ 6	23	91.08	+ 6	170	10,116
+ 5	19	91.00	+ 5	142	10,140
+ 4	15	90.92	+ 4	114	10,163
+ 3	11	90.84	+ 3	85	10,187
+ 2	8	90.76	+ 2	57	10,210
+ 1	4	90.68	+ 1	28	10,234
				0	10,257
0	0	90.60	0	0	10,332
				0	10,407
- 1	(5)	90.48	- 1	(28)	10,431
- 2	(9)	90.36	- 2	(57)	10,454
- 3	(14)	90.24	- 3	(85)	10,478
- 4	(18)	90.12	- 4	(114)	10,501
- 5	(23)	90.00	- 5	(142)	10,525
- 6	(27)	89.88	- 6	(170)	10,548
- 7	(32)	89.76	- 7	(199)	10,572
- 8	(36)	89.64	- 8	(227)	10,595
- 9	(41)	89.52	- 9	(256)	10,619
- 10	(45)	89.40	- 10	(284)	10,642
Weighting Factor:		0.005	Weighting Factor:		0.041

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	81	90.20	+ 10	369	9,833
+ 9	73	90.10	+ 9	332	9,856
+ 8	65	90.00	+ 8	295	9,879
+ 7	57	89.90	+ 7	258	9,902
+ 6	49	89.80	+ 6	221	9,925
+ 5	41	89.70	+ 5	185	9,948
+ 4	32	89.60	+ 4	148	9,970
+ 3	24	89.50	+ 3	111	9,993
+ 2	16	89.40	+ 2	74	10,016
+ 1	8	89.30	+ 1	37	10,039
				0	10,062
0	0	89.20	0	0	10,137
				0	10,212
- 1	(13)	89.04	- 1	(37)	10,235
- 2	(27)	88.88	- 2	(74)	10,258
- 3	(40)	88.72	- 3	(111)	10,281
- 4	(53)	88.56	- 4	(148)	10,304
- 5	(67)	88.40	- 5	(185)	10,327
- 6	(80)	88.24	- 6	(221)	10,349
- 7	(93)	88.08	- 7	(258)	10,372
- 8	(106)	87.92	- 8	(295)	10,395
- 9	(120)	87.76	- 9	(332)	10,418
- 10	(133)	87.60	- 10	(369)	10,441
Weighting Factor:		0.012	Weighting Factor:		0.053

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	539	78.40	+ 10	1,156	9,930
+ 9	485	78.09	+ 9	1,040	9,953
+ 8	431	77.78	+ 8	925	9,976
+ 7	377	77.47	+ 7	809	10,000
+ 6	323	77.16	+ 6	694	10,023
+ 5	270	76.85	+ 5	578	10,046
+ 4	216	76.54	+ 4	462	10,069
+ 3	162	76.23	+ 3	347	10,092
+ 2	108	75.92	+ 2	231	10,116
+ 1	54	75.61	+ 1	116	10,139
				0	10,162
0	0	75.30	0	0	10,237
				0	10,312
- 1	(88)	74.85	- 1	(116)	10,335
- 2	(175)	74.40	- 2	(231)	10,358
- 3	(263)	73.95	- 3	(347)	10,382
- 4	(350)	73.50	- 4	(462)	10,405
- 5	(438)	73.05	- 5	(578)	10,428
- 6	(525)	72.60	- 6	(694)	10,451
- 7	(613)	72.15	- 7	(809)	10,474
- 8	(700)	71.70	- 8	(925)	10,498
- 9	(788)	71.25	- 9	(1,040)	10,521
- 10	(875)	70.80	- 10	(1,156)	10,544
Weighting Factor:		0.078	Weighting Factor:		0.167

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Docket No.: 990001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2000 - December 2000

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	454	77.20	+ 10	1,227	9,802
+ 9	409	76.93	+ 9	1,104	9,825
+ 8	363	76.66	+ 8	982	9,848
+ 7	318	76.39	+ 7	859	9,870
+ 6	272	76.12	+ 6	736	9,893
+ 5	227	75.85	+ 5	614	9,916
+ 4	182	75.58	+ 4	491	9,939
+ 3	136	75.31	+ 3	368	9,962
+ 2	91	75.04	+ 2	245	9,984
+ 1	45	74.77	+ 1	123	10,007
				0	10,030
0	0	74.50	0	0	10,105
				0	10,180
- 1	(76)	74.08	- 1	(123)	10,203
- 2	(151)	73.66	- 2	(245)	10,226
- 3	(227)	73.24	- 3	(368)	10,248
- 4	(302)	72.82	- 4	(491)	10,271
- 5	(378)	72.40	- 5	(614)	10,294
- 6	(453)	71.98	- 6	(736)	10,317
- 7	(529)	71.56	- 7	(859)	10,340
- 8	(604)	71.14	- 8	(982)	10,362
- 9	(680)	70.72	- 9	(1,104)	10,385
- 10	(755)	70.30	- 10	(1,227)	10,408
Weighting Factor:		0.065	Weighting Factor:		0.177

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Order No.:

ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 6	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	43.7	9.8	90.2	90.3	96.8	96.8	
2.	POF (%)	54.8	89.7	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.5	0.5	9.8	9.7	3.2	3.2	
4.	EUOR (%)	3.3	5.6	9.8	9.7	3.2	3.2	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	325.0	70.0	674.0	649.0	720.0	697.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	419.0	626.0	70.0	70.0	24.0	23.0	
9.	POH	408.0	624.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	11.0	4.0	25.0	22.0	24.0	23.0	
11.	MOH & EMOH	0.0	0.0	48.0	48.0	0.0	0.0	
12.	Oper MBtu	806319.0	178381.0	1810311.0	1657028.0	1743423.0	1873638.0	
13.	Net Gen (MWH)	75590.0	16740.0	170190.0	158340.0	165050.0	176160.0	
14.	ANOHR (Btu/KWH)	10667.0	10656.0	10637.0	10465.0	10563.0	10636.0	
15.	NOF %	77.0	79.2	83.6	80.8	75.9	83.7	
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY] + 10,287

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Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 6	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	96.8	96.8	96.8	96.8	96.8	96.8	84.3
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	11.7
3.	EUOF (%)	3.2	3.2	3.2	3.2	3.2	3.2	4.0
4.	EUOR (%)	3.2	3.2	3.2	3.2	3.2	3.2	4.5
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	720.0	720.0	697.0	721.0	697.0	720.0	7410.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	24.0	24.0	23.0	24.0	23.0	24.0	1374.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1032.0
10.	FOH & EFOH	24.0	24.0	23.0	24.0	23.0	24.0	251.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	96.0
12.	Oper MBtu	1929020.0	1996119.0	1766137.0	1797479.0	1666285.0	1641473.0	18865613.0
13.	Net Gen (MWH)	181350.0	187870.0	165710.0	168540.0	155990.0	153380.0	1774910.0
14.	ANOHR (Btu/KWH)	10637.0	10625.0	10658.0	10665.0	10682.0	10702.0	10629.0
15.	NOF %	83.4	86.4	78.7	77.4	74.1	70.5	79.3
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [88.29 - 44.75 * APR - 24.93 * MAY] + 10,287

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GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 7	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00
1.	EAF (%)	91.9	78.6	0.0	45.9	91.9	91.9
2.	POF (%)	0.0	13.8	100.0	50.1	0.0	0.0
3.	EUOF (%)	8.1	7.6	0.0	4.0	8.1	8.1
4.	EUOR (%)	8.1	8.8	0.0	8.1	8.1	8.1
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0
6.	SH	684.0	552.0	0.0	330.0	684.0	662.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	60.0	144.0	744.0	389.0	60.0	58.0
9.	POH	0.0	96.0	744.0	360.0	0.0	0.0
10.	FOH & EFOH	60.0	53.0	0.0	29.0	60.0	58.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0
12.	Oper MBtu	2946599.0	2419159.0	0.0	1462196.0	2946238.0	3081530.0
13.	Net Gen (MWH)	287810.0	236500.0	0.0	143030.0	283920.0	302170.0
14.	ANOHR (Btu/KWH)	10238.0	10229.0	-	10223.0	10377.0	10198.0
15.	NOF %	90.5	92.1	0.0	93.2	89.3	98.2
16.	NPC (MW)	465.0	465.0	465.0	465.0	465.0	465.0

19.	ANOHR Equation	$10^6 / AKW * [215.83 + 54.63 * MAY] + 9,725$

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GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	CRIST 7	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	91.9	91.9	85.8	86.0	85.8	86.0	77.3
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	13.7
3.	EUOF (%)	8.1	8.1	14.2	14.0	14.2	14.0	9.0
4.	EUOR (%)	8.1	8.1	14.2	14.0	14.2	14.0	10.4
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	684.0	684.0	618.0	641.0	618.0	640.0	6797.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	60.0	60.0	102.0	104.0	102.0	104.0	1987.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1200.0
10.	FOH & EFOH	60.0	60.0	54.0	56.0	54.0	56.0	600.0
11.	MOH & EMOH	0.0	0.0	48.0	48.0	48.0	48.0	192.0
12.	Oper MBtu	3159457.0	3231158.0	2695869.0	2798792.0	2773644.0	2651131.0	30165773.0
13.	Net Gen (MWH)	309690.0	317060.0	263500.0	273560.0	271500.0	258420.0	2947160.0
14.	ANOHR (Btu/KWH)	10202.0	10191.0	10231.0	10231.0	10216.0	10259.0	10236.0
15.	NOF %	97.4	99.7	91.7	91.8	94.5	86.8	93.2
16.	NPC (MW)	465.0	465.0	465.0	465.0	465.0	465.0	465.0

19.	ANOHR Equation	10^6 / AKW * [215.83 + 54.63 * MAY] + 9,725

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 1	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	98.1	44.0	98.1	87.8	98.1	98.2	
2.	POF (%)	0.0	55.2	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.9	0.8	1.9	12.2	1.9	1.8	
4.	EUOR (%)	1.9	1.9	1.9	12.2	1.9	1.8	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	730.0	306.0	730.0	635.0	730.0	707.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	14.0	390.0	14.0	84.0	14.0	13.0	
9.	POH	0.0	384.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	14.0	6.0	14.0	16.0	14.0	13.0	
11.	MOH & EMOH	0.0	0.0	0.0	72.0	0.0	0.0	
12.	Oper MBtu	812745.0	378584.0	954932.0	800959.0	824915.0	921340.0	
13.	Net Gen (MWH)	77730.0	36610.0	92820.0	78510.0	80190.0	89520.0	
14.	ANOHR (Btu/KWH)	10456.0	10341.0	10288.0	10202.0	10287.0	10292.0	
15.	NOF %	65.7	73.9	78.5	76.3	67.8	78.2	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV] + 5,563 + 0.01691 * LSRF / AKW

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Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 1	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	98.1	98.1	98.2	98.1	68.8	98.1	90.6
2.	POF (%)	0.0	0.0	0.0	0.0	30.0	0.0	6.8
3.	EUOF (%)	1.9	1.9	1.8	1.9	1.2	1.9	2.6
4.	EUOR (%)	1.9	1.9	1.8	1.9	1.8	1.9	2.8
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	730.0	730.0	707.0	731.0	495.0	730.0	7961.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	14.0	14.0	13.0	14.0	225.0	14.0	823.0
9.	POH	0.0	0.0	0.0	0.0	216.0	0.0	600.0
10.	FOH & EFOH	14.0	14.0	13.0	14.0	9.0	14.0	155.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	72.0
12.	Oper MBtu	966761.0	982888.0	858222.0	894309.0	580676.0	769135.0	9745466.0
13.	Net Gen (MWH)	93110.0	95770.0	82840.0	86390.0	56690.0	73070.0	943250.0
14.	ANOHR (Btu/KWH)	10383.0	10263.0	10360.0	10352.0	10243.0	10526.0	10332.0
15.	NOF %	78.7	81.0	72.3	73.0	70.7	61.8	73.1
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19. ANOHR Equation: 10^6 / AKW * [303.56 - 13.60 * APR - 14.98 * MAY + 12.46 * JUL - 15.94 * NOV]
+ 5,563 + 0.01691 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 2	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	96.9	97.0	96.9	90.4	46.4	96.9	
2.	POF (%)	0.0	0.0	0.0	0.0	51.6	0.0	
3.	EUOF (%)	3.1	3.0	3.1	9.6	2.0	3.1	
4.	EUOR (%)	3.1	3.0	3.1	9.6	4.2	3.1	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	721.0	675.0	721.0	650.0	349.0	698.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	23.0	21.0	23.0	69.0	395.0	22.0	
9.	POH	0.0	0.0	0.0	0.0	384.0	0.0	
10.	FOH & EFOH	23.0	21.0	23.0	21.0	15.0	22.0	
11.	MOH & EMOH	0.0	0.0	0.0	48.0	0.0	0.0	
12.	Oper MBtu	1070480.0	1063949.0	1203549.0	1048280.0	531004.0	1178067.0	
13.	Net Gen (MWH)	105810.0	105540.0	119780.0	104120.0	51780.0	116100.0	
14.	ANOHR (Btu/KWH)	10117.0	10081.0	10048.0	10068.0	10255.0	10147.0	
15.	NOF %	76.0	81.0	86.1	83.0	76.9	86.2	
16.	NPC (MW)	193.0	193.0	193.0	193.0	193.0	193.0	
19.	ANOHR Equation	10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP] + 9,526						

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	SMITH 2	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	96.9	96.9	96.9	96.9	77.5	81.3	89.2
2.	POF (%)	0.0	0.0	0.0	0.0	20.0	16.1	7.4
3.	EUOF (%)	3.1	3.1	3.1	3.1	2.5	2.6	3.4
4.	EUOR (%)	3.1	3.1	3.1	3.1	3.1	3.0	3.7
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	721.0	721.0	698.0	722.0	558.0	605.0	7839.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	23.0	23.0	22.0	23.0	162.0	139.0	945.0
9.	POH	0.0	0.0	0.0	0.0	144.0	120.0	648.0
10.	FOH & EFOH	23.0	23.0	22.0	23.0	18.0	19.0	253.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	48.0
12.	Oper MBtu	1221988.0	1268979.0	1067990.0	1123208.0	881597.0	842892.0	12501983.0
13.	Net Gen (MWH)	119230.0	124300.0	104890.0	111330.0	87460.0	82970.0	1233310.0
14.	ANOHR (Btu/KWH)	10249.0	10209.0	10182.0	10089.0	10080.0	10159.0	10137.0
15.	NOF %	85.7	89.3	77.9	79.9	81.2	71.1	81.5
16.	NPC (MW)	193.0	193.0	193.0	193.0	193.0	193.0	193.0
19.	ANOHR Equation	10^6 / AKW * [86.76 + 21.35 * MAY + 16.56 * JUN + 32.76 * JUL + 30.95 * AUG + 11.83 * SEP] + 9,526						

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GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 1	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	92.9	79.7	0.0	65.0	92.9	92.9	
2.	POF (%)	0.0	13.8	100.0	29.9	0.0	0.0	
3.	EUOF (%)	7.1	6.5	0.0	5.1	7.1	7.1	
4.	EUOR (%)	7.1	7.5	0.0	7.3	7.1	7.1	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	691.0	557.0	0.0	468.0	691.0	669.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	53.0	139.0	744.0	251.0	53.0	51.0	
9.	POH	0.0	96.0	744.0	215.0	0.0	0.0	
10.	FOH & EFOH	53.0	45.0	0.0	37.0	53.0	51.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3090911.0	2561398.0	0.0	2124665.0	2701075.0	2880504.0	
13.	Net Gen (MWH)	301670.0	248390.0	0.0	206780.0	259270.0	284410.0	
14.	ANOHR (Btu/KWH)	10246.0	10312.0	-	10275.0	10418.0	10128.0	
15.	NOF %	91.3	93.3	0.0	86.6	73.6	83.4	
16.	NPC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN] + 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

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GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 1	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	92.9	92.9	92.9	45.0	65.0	92.9	75.3
2.	POF (%)	0.0	0.0	0.0	29.0	0.0	0.0	14.5
3.	EUOF (%)	7.1	7.1	7.1	26.0	35.0	7.1	10.2
4.	EUOR (%)	7.1	7.1	7.1	36.7	35.0	7.1	11.9
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	691.0	691.0	669.0	335.0	468.0	691.0	6621.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	53.0	53.0	51.0	410.0	252.0	53.0	2163.0
9.	POH	0.0	0.0	0.0	216.0	0.0	0.0	1271.0
10.	FOH & EFOH	53.0	53.0	51.0	26.0	36.0	53.0	511.0
11.	MOH & EMOH	0.0	0.0	0.0	168.0	216.0	0.0	384.0
12.	Oper MBtu	2991214.0	3130245.0	2682254.0	1413229.0	1917545.0	2524184.0	28017224.0
13.	Net Gen (MWH)	293170.0	309160.0	261990.0	139070.0	188290.0	244710.0	2736910.0
14.	ANOHR (Btu/KWH)	10203.0	10125.0	10238.0	10162.0	10184.0	10315.0	10237.0
15.	NOF %	83.2	87.7	76.8	81.4	78.9	69.4	82.3
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	502.0

19. ANOHR Equation: 10^6 / AKW * [1223.24 - 40.12 * JAN - 50.48 * MAR - 44.86 * JUN]

+ 9,170 + 10^6 / AKW * [-0.0731 * BTU/LB]

Issued by: T. J. Bowden

Filed: October 1, 1999
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Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 2	Jan '00	Feb '00	Mar '00	Apr '00	May '00	Jun '00	
1.	EAF (%)	57.7	80.7	51.6	87.2	94.1	94.0	
2.	POF (%)	0.0	0.0	45.2	6.7	0.0	0.0	
3.	EUOF (%)	42.3	19.3	3.2	6.1	5.9	6.0	
4.	EUOR (%)	42.3	19.3	5.9	6.6	5.9	6.0	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	429.0	564.0	384.0	631.0	700.0	677.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	315.0	132.0	360.0	88.0	44.0	43.0	
9.	POH	0.0	0.0	336.0	48.0	0.0	0.0	
10.	FOH & EFOH	27.0	38.0	24.0	44.0	44.0	43.0	
11.	MOH & EMOH	288.0	96.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1950232.0	2589460.0	1787035.0	2858388.0	2785630.0	2995265.0	
13.	Net Gen (MWH)	194770.0	256560.0	177250.0	283880.0	273530.0	298720.0	
14.	ANOHR (Btu/KWH)	10013.0	10093.0	10082.0	10069.0	10184.0	10027.0	
15.	NOF %	95.0	95.2	96.6	88.2	76.6	86.5	
16.	NPC (MW)	478.0	478.0	478.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP] + 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]

Issued by: T. J. Bowden

Filed: October 1, 1999
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Effective: January 1, 2000
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2000 - December 2000

	DANIEL 2	Jul '00	Aug '00	Sep '00	Oct '00	Nov '00	Dec '00	Total
1.	EAF (%)	94.1	94.1	69.0	0.1	78.3	94.1	74.5
2.	POF (%)	0.0	0.0	26.7	99.9	16.7	0.0	16.4
3.	EUOF (%)	5.9	5.9	4.3	0.0	5.0	5.9	9.1
4.	EUOR (%)	5.9	5.9	5.9	0.0	6.0	5.9	10.9
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	700.0	700.0	497.0	1.0	564.0	700.0	6547.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	44.0	44.0	223.0	744.0	156.0	44.0	2237.0
9.	POH	0.0	0.0	192.0	744.0	120.0	0.0	1440.0
10.	FOH & EFOH	44.0	44.0	31.0	0.0	36.0	44.0	419.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	384.0
12.	Oper MBtu	3120154.0	3271151.0	2065417.0	0.0	2303875.0	2603652.0	28330259.0
13.	Net Gen (MWH)	306830.0	323460.0	201760.0	0.0	229790.0	257100.0	2803650.0
14.	ANOHR (Btu/KWH)	10169.0	10113.0	10237.0	-	10026.0	10127.0	10105.0
15.	NOF %	85.9	90.6	79.6	0.0	79.9	72.0	85.3
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	502.0

19.	ANOHR Equation	10^6 / AKW * [1014.82 - 37.91 * JAN + 69.66 * JUL + 78.80 * AUG + 76.66 * SEP] + 9,052 + 10^6 / AKW * [-0.0554 * BTU/LB]

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Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2000 - December 2000

Plant & Unit	Planned Outage Dates	Reason for Outage
Crist 6	01/15/2000 - 02/26/2000	Annual general boiler maintenance and inspection.
Crist 7	02/26/2000 - 04/15/2000	Annual general boiler maintenance and inspection.
Smith 1	02/05/2000 - 02/20/2000	Semi-annual general boiler maintenance and inspection.
Smith 1	11/04/2000 - 11/12/2000	Semi-annual general boiler maintenance and inspection.
Smith 2	05/13/2000 - 05/28/2000	Semi-annual general boiler maintenance and inspection.
Smith 2	11/25/2000 - 12/05/2000	Semi-annual general boiler maintenance and inspection.
Daniel 1	02/26/2000 - 04/09/2000	General boiler maintenance, inspection, and stack repair.
Daniel 1	10/21/2000 - 10/29/2000	Semi-annual general boiler maintenance and inspection.
Daniel 2	03/18/2000 - 04/02/2000	General boiler maintenance, inspection, and stack repair.
Daniel 2	09/23/2000 - 11/05/2000	Semi-annual general boiler maintenance and inspection.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2000 - December 2000

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2000 - December 2000, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage

None

Filed: October 1, 1999
Suspended:
Effective: January 1, 2000
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IV. PROPOSED CHANGES TO THE GPIF IMPLEMENTATION MANUAL

III. Gulf Power Company

3.1 Definitions

The following definitions are applicable in addition to those shown in Section 2, Technical Terms and Abbreviations.

Term	Abbreviations
Average Kilowatt Load	AKW
The average kilowatt load that a unit was operated at during a given period of time. $AKW = \frac{KWH}{\Sigma HR_i}$	
Coal BTU	BTUC
BTU boiler input from coal fuel including lighter oil amounts, during a specified calendar period of time.	
Gas BTU	BTUG
BTU boiler input from gas fuel during a specified calendar period of time	
Average Net Operating Heat Rate	Oper. BTU/AKW HR
The average net operating heat rate during a specified period of time.	
Input/Output Equation Regression Constant	C1
Input/Output Equation Regression Coefficients	C2, C3, C4 ... Cn
Gas Adjustment Factor	GF
Conversion factor for converting gas BTU boiler input for converting coal BTU boiler input.	
Coal Heat Content	***BTU/LB***
Average heating value of coal fuel consumed over a given period of time. This independent variable may be used when required to produce an adequate target equation.	

Term	Abbreviations
Hour	HR
Hours at Load i Number of hours during a specified calendar period of time the unit was operated at the i th kilowatt load level.	HR_i
Number of Operating Hours Number of hours during a specified calendar period of time the unit was operated.	ΣHR_i
i th Kilowatt Output Level The i th net kilowatt output level of the unit during a specified calendar period of time.	KW_i
Load Square Range Factor A combinant variable considering the weighted amount of time a unit was loaded at various KW load levels and the square of the load. $LSRF = \frac{\Sigma KW_i^2 * HR_i}{\Sigma HR_i}$	LSRF
Start up Energy Energy input to the boiler during unit start up and prior to synchronization.	SUE
Causative Variables Independent unit related variables upon which it is hypothesized that the BTU consumption rate for the unit may depend.	$VAR_1, VAR_2, \ldots VAR_n$

3.2 Basis for Generating Unit Selection

The annual fuel and purchased energy savings to the Company's customers estimated to result from improving equivalent availability by thee percent (3%), where not limited, and from improving heat rate one hundred (100) BTU/KWH shall be calculated for each eligible unit.

Those units with the largest savings estimates which comprise approximately eighty percent (80%) of the total estimated savings associated with improving all eligible units, shall be selected for inclusion in the GPIF.

Eligible units shall mean steam units which have been commercially operated by the Company for at least one year, are no longer under manufacturers warranty, and whose efficiency and reliability characteristics are not expected to be altered by any ongoing research during the performance period.

3.2.1 Generating Units

Units meeting the GPIF criteria are:

Christ 6
Christ 7
Smith 1
Smith 2
Daniel 1
Daniel 2

3.3 Methodology for Determination of Equivalent Availability Targets and Ranges.

3.3.1 Equivalent Availability Targets

3.3.1.1 Target Equivalent Availability Equation

The equivalent availability target shall be determined for each unit included in the GPIF by determining performance period values for period hours (PH), planned outage hours (POH), reserve shutdown hours (RSH), and equivalent unplanned outage rate (EUOR), substituting these into the following equation, and completing the calculation for target equivalent availability (EA).

$$\text{Eqn. 1} \quad EA = \left[1 - \frac{POH + EUOR * (PH - POH - RSH)}{PH}\right] * 100$$

3.3.1.2 Target Planned Outage Hours

The target planned outage hours, POH, to be used in equation 1 shall be determined for each GPIF unit as the sum of the expected durations of all planned outages *forecast to occur within the performance period for the* particular unit.

The duration of each planned outage shall be based upon similar historical outage experience, the work scope of the outage, estimates of subcontractors, vendor recommendations, management judgement or a combination of the above.

Where a planned outage for inspection is involved, the outage duration forecast will consider the uncovering and correction of typical minor problem areas only, unless there is significant reason to believe that major corrective action may be required.

3.3.1.3 Reserve Shutdown Hours

Reserve shutdown hours for each GPIF unit shall be forecast as zero for the performance period unless there is significant evidence that reserve shutdown hours will not be zero.

3.3.1.4 Target Equivalent Unplanned Outage Rate

The target equivalent unplanned outage rate for each GPIF unit shall be determined as the five year historical average of the equivalent unplanned outage rates for the same calendar period as the performance period. The equivalent unplanned outage rate for each similar historical period shall be calculated as:

$$\text{Eqn. 2} \quad EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)}$$

3.3.2 Equivalent Availability Ranges

3.3.2.1 Maximum Attainable Equivalent Availability

The maximum attainable equivalent availability for each unit shall be determined as was the target equivalent availability except that the next to the best (lowest) quivalent unplanned outage rate, EUOR, experienced by the unit in the last five similar historical periods shall be used.

3.3.2.2 Minimum Attainable Equivalent Availability

The minimum attainable equivalent availability for each unit shall be determined as the lower of:

The equivalent availability which results from using the next to the worst (highest) equivalent unplanned outage rate, EUOR, experienced by the unit in the last five similar historical periods along with target planned outage hours in equation 1, or

the equivalent availability which results from deducting the difference between the maximum attainable equivalent availability and the target equivalent availability for the unit from the target equivalent availability.

3.4 Methodology for Determination of Heat Rate Targets and Ranges

3.4.1 Average heat Rate Targets

3.4.1.1 Use of Multiple Least Squares Regression Analysis

Average heat rate targets for each unit included in the GPIF shall be determined from multiple least squares regression analyses of each unit's historic BTU energy consumption per hour as a function of certain causative variables.

The general form of the input/output equation used for analysis shall be:

Eqn. 1 $$\frac{\text{Oper. BTU}}{\text{HR}} = \frac{\text{BTUC} + \text{GF} * \text{BTUG} - \text{SUE}}{\text{HR}_i} = C1 + C2 * AKW + C3 * LSRF + C4 * VAR1 + \ldots + CN * VAR_n + \textbf{\textit{C5 * BTU/LB}}$$

The final term (C5 * BTU/LB) may be used when significant changes in coal heat content between the historical and forecast values are expected.

3.4.1.2 Determination of Regression Coefficients

The regression constants of each unit's input/output equation shall be determined by applying Equation 1 to weekly observations from the most recent three (3) years operating experience of the unit.

Where three years of the necessary actual observation data is not available, the most recent data available of lesser period shall be used.

Actual observation data which is known to be defective, such as may result from inoperative or malfunctioning fuel measuring equipment, or whose BTU/HR value differs by ten percent (10%) or more from its predicted value based upon an initial regression equation shall be eliminated. Eliminated data will not be used for determining the regression coefficients of the input/output equation utilized to set the unit heat rate target.

Stepwise regression analysis shall be used, and no causative variable shall be retained in the target input/output equation if the coefficient associated with such variable is not significant using a ninety percent (90%) confidence interval.

If stepwise regression does not result in the retention of either unit load variable, AKW or LSRF, the more significant of the two will be retained in the target input/output equation, the previous paragraph notwithstanding.

In the case of intercorrelated causative variables, other than AWK and LSRF, the more significant variable will be retained in the target input/output equation and the related variable(s) discarded.

3.4.1.3 Determination of Target Heat Rate Equation from Target Input/Output Equation

The input/output equations developed per paragraphs 3.4.1.1 and 3.4.1.2 shall be converted to average net operating heat rate equations by dividing both sides of equation 1 by the average kilowatt load, AKW. The result is as shown below:

$$\text{Eqn. 2 } ANOHR = \frac{\text{Oper. BTU}}{AWK * HR} = \frac{(C1 + C4 * VAR1 + \ldots + Cn * VARn)}{AKW} + C2 + C3 * \frac{LSRF}{AKW} + C5 * \frac{BTU/LB}{AKW}$$

3.4.1.4 Determination of Average Heat Rate Targets

The target average heat rate for each GPIF unit shall be determined by forecasting values for the independent (causative) variables of equation 2 for the future GPIF performance period, inserting these values into equation 2, and completing the calculation for the target heat rate, ANOHR. ***Independent variable BTU/LB need only be forecast and used when necessary to account for significant differences in coal heat content between the historical and the forecast values.***

3.4.1.5 Alterations to Target Heat Rate Methodology

Should an adequate number of data observations to produce equation 2 for each GPIF unit be unavailable, or should a unit be scheduled to be physically altered in the performance period by government mandate or because of the economic benefit of such alteration to Company and Customer and such alteration will adversely affect the unit's heat rate characteristics, the Company shall either obtain the necessary number of observations from an earlier period, use engineering analyses,

other appropriate means, or a combination of these as warranted to produce equation 2. If one of the aforementioned alternative methods is necessary, the Company shall use and present to the Commission the methodology which it believes best represents what the input/output curve of the subject GPIF unit will be in the performance period assuming there is no additional action or inaction regarding the unit by the Company beyond current practice.

If for some reason the future value of a causative variable, other than those related to operating load levels, cannot be reliably determined, the Company shall estimate to the best of its engineering expertise the value of the term in equation 2 for the performance period.

3.4.1.6 Gas Factor

The gas factor, GF, shall be calculated from actual operating data for each coal/gas burning unit individually.

3.4.2 Average Heat Rate Ranges

The minimum attainable heat rate value for the performance period for each GPIF unit shall be established at ninety seven percent (97%) of the target heat rate.

The maximum attainable heat rate value for the performance period for each GPIF unit shall be established at one hundred and three percent (103%) of the target heat rate.

3.4.3 Adjustments to Average Heat Rage

Since performance targets are set prospectively in the GPIF, certain circumstances may arise during the six month period which warrant adjustments to be made in the final GPIF calculation. Adjustments to the average heat rate performance indicator are necessary to reflect differences between actual values which occurred during the period and forecast values of variables used as part of the target heat rate setting methodology, and may be necessary to offset the effect of an externally caused disaster. A prime example of the first type of adjustment are adjustments needed to reflect changes in the economic dispatch of units not anticipated in advance. An example of the second type of adjustment might be continued economic operation of an efficiency impaired turbine where the impairment was the result of blade damage predicated by material failure or blade removal based upon vendor recommendation.

Adjustment for differences between actual and forecast values of the target setting variables shall be calculated as the target heat rate less what the target heat rate would have been established at had the actual variable values been known for the unit for the period.

Table 1 graphically illustrates the method for calculating the adjustment for a single target setting variable. The adjustment to the actual average heat rate performance indicator is the vertical distance between the target average heat rate curve at the actual variable value for the period and the target average heat rate curve at the forecasted variable value for the period.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 990001-EI

Before me the undersigned authority, personally appeared James R. Douglass, who being first duly sworn, deposes, and says that he is the Performance Test Specialist for Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

James R. Douglass
Performance Test Specialist

Sworn to and subscribed before me this 29th day of September, 1999.

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION # CC 667388
EXPIRES: February 26, 2002
Bonded Thru Notary Public Underwriters

15

ATTACHMENT "A"
October 1, 1999

TAMPA ELECTRIC COMPANY
GPIF TARGETS
January 1, 2000 - December 31, 2000

Availability				Heat Rate
Unit	**EAF**	**POF**	**EUOF**	
Gannon 5	75.3	5.7	19.0	10,562[1/]
Gannon 6	72.2	5.7	22.1	10,507[2/]
Big Bend 1	78.1	5.7	16.1	10,127[3/]
Big Bend 2	80.6	4.9	14.5	10,061[4/]
Big Bend 3	76.3	5.7	18.0	10,197[5/]
Big Bend 4	84.4	1.9	13.7	9,976[6/]

[1/] Original Sheet 8.401.99E, Pg. 13

[2/] Original Sheet 8.401.99E, Pg. 14

[3/] Original Sheet 8.401.99E, Pg. 15

[4/] Original Sheet 8.401.99E, Pg. 16

[5/] Original Sheet 8.401.99E, Pg. 17

[6/] Original Sheet 8.401.99E, Pg. 18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 15
COMPANY/ WITNESS: K. Edelgundsky
DATE: 11-22-99

16

EXHIBIT NO. _____
DOCKET NO. 000001 - EI
TAMPA ELECTRIC COMPANY
(GAK-2)
PAGE 1 OF 35

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2000 - DECEMBER 2000
TABLE OF CONTENTS

SCHEDULE	PAGE
GPIF REWARD / PENALTY TABLE ESTIMATED	2
GPIF CALCULATIONS OF MAXIMUM ALLOWED INCENTIVE DOLLARS	3
GPIF TARGET AND RANGE SUMMARY	4
COMPARISION GPIF TARGETS VS PRIOR PERIODS ACTUAL PERFORMANCE	5
GPIF HEAT RATE SUMMARY	5
DERIVATION OF WEIGHTING FACTORS	6
GENERATING PERFORMANCE INCENTIVE POINT TABLES	7 - 12
ESIMATED UNIT PERFORMANCE DATA	13 - 18
PLANNED OUTAGE SCHEDULE	19
CRITICAL PATH METHOD DIAGRAMS	20
TAMPA ELECTRIC COMPANY FORCED OUTAGE AND MAINTENANCE OUTAGE FACTOR GRAPHS	21 - 26
NET HEAT RATE VS NET OUTPUT FACTOR GRAPHS	27 - 32
GENERATING UNITS IN GPIF (TABLE 4.2 IN MANUAL)	33
UNIT RATINGS AS OF OCTOBER 1, 1999	34
PROJECTED PERCENT GENERATION BY UNIT	35

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 16
COMPANY/ WITNESS: Koeleman
DATE: 11-22-99

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS TABLE
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2000 - DECEMBER 2000

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	15,734.0	4,943.1
+9	14,160.6	4,448.8
+8	12,587.2	3,954.5
+7	11,013.8	3,460.2
+6	9,440.4	2,965.9
+5	7,867.0	2,471.6
+4	6,293.6	1,977.3
+3	4,720.2	1,482.9
+2	3,146.8	988.6
+1	1,573.4	494.3
0	0	0.0
-1	(2,395.8)	(494.3)
-2	(4,791.6)	(988.6)
-3	(7,187.5)	(1,482.9)
-4	(9,583.3)	(1,977.3)
-5	(11,979.1)	(2,471.6)
-6	(14,374.9)	(2,965.9)
-7	(16,770.7)	(3,460.2)
-8	(19,166.6)	(3,954.5)
-9	(21,562.4)	(4,448.8)
-10	(23,958.2)	(4,943.1)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
ESTIMATED
JANUARY 2000 - DECEMBER 2000

Line 1	Beginning of period balance of common equity End of month common equity:			$1,202,600,000
Line 2	Month of	January	2000	$1,201,801,000
Line 3	Month of	February	2000	$1,213,569,000
Line 4	Month of	March	2000	$1,225,452,000
Line 5	Month of	April	2000	$1,214,599,000
Line 6	Month of	May	2000	$1,226,492,000
Line 7	Month of	June	2000	$1,238,501,000
Line 8	Month of	July	2000	$1,237,579,000
Line 9	Month of	August	2000	$1,249,697,000
Line 10	Month of	September	2000	$1,261,933,000
Line 11	Month of	October	2000	$1,250,858,000
Line 12	Month of	November	2000	$1,263,106,000
Line 13	Month of	December	2000	$1,275,474,000
Line 14	(summation of line 1 through line 13 divided by 13)			$1,235,512,385
Line 15	25 Basis points			0.0025
Line 16	Revenue expansion factor			61.3738%
Line 17	Maximum allowed incentive Dollars (Line 14 times line 15 divided by line 16)			$5,032,735
Line 18	Jurisdictional Sales			16644004 MWH
Line 19	Total Sales			16945711 MWH
Line 20	Jurisdictional Seperation Factor (Line 18 divided by line 19)			98.22%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (Line 17 times line 20)			$4,943,131

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2000 - DECEMBER 2000

EQUIVALENT AVAILABILITY

PLANT/UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF MAX. (%)	RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
GANNON 5	2.79%	75.3	79.3	67.1	435.3	(1,098.3)
GANNON 6	8.49%	72.2	76.9	62.9	1,326.3	(2,837.0)
BIG BEND 1	8.45%	78.1	81.7	71.1	1,319.2	(2,856.0)
BIG BEND 2	6.47%	80.6	83.8	74.4	1,010.3	(2,749.8)
BIG BEND 3	8.71%	76.3	79.6	67.6	1,359.8	(2,945.8)
BIG BEND 4	7.71%	84.4	87.1	78.6	1,203.7	(2,364.4)
GPIF SYSTEM	42.62%				6,654.6	(14,851.3)

AVERAGE NET OPERATING HEAT RATE
FOR
GPIF COAL GENERATING UNITS

PLANT/UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
GANNON 5	5.37%	10562	66.7	10158	10966	839.0	(839.0)
GANNON 6	7.47%	10507	68.1	10141	10873	1,166.0	(1,166.0)
BIG BEND 1	11.53%	10127	87.1	9740	10514	1,801.0	(1,801.0)
BIG BEND 2	11.54%	10061	91.0	9693	10429	1,802.0	(1,802.0)
BIG BEND 3	10.80%	10197	80.6	9816	10578	1,686.0	(1,686.0)
BIG BEND 4	10.67%	9976	88.7	9660	10292	1,665.0	(1,665.0)
GPIF SYSTEM	57.38%					8,959.0	(8,959.0)

TAMPA ELECTRIC COMPANY

COMPARISON OF OPIF TARGETS VS. PRIOR PERIOD ACTUAL PERFORMANCE

AVAILABILITY

PLANT/UNIT	TARGET WEIGHTING FACTOR	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 00 - DEC 00 POF	EUOF	EUOR	TARGET PERIOD AUG 98 - JUL 99 POF	EUOF	EUOR	TARGET PERIOD AUG 97 - JUL 98 POF	EUOF	EUOR	TARGET PERIOD AUG 96 - JUL 97 POF	EUOF	EUOR
BIG BEND 1	8.45%	19.8	5.7	16.1	17.1	6.9	18.2	19.5	10.0	16.3	18.1	15.9	17.9	21.3
BIG BEND 2	6.47%	15.2	4.9	14.5	15.2	0.0	19.4	19.4	5.3	14.1	14.9	3.3	11.7	12.1
BIG BEND 3	8.71%	20.4	5.7	18.0	19.1	15.8	19.8	23.5	4.7	20.3	21.3	2.6	18.8	19.3
BIG BEND 4	7.71%	18.1	1.9	13.7	14.0	6.3	15.1	16.1	3.2	11.4	11.8	6.0	8.1	8.6
GANNON 5	2.79%	6.5	5.7	19.0	20.2	6.6	25.0	26.8	10.3	24.1	26.9	5.6	23.1	24.5
GANNON 6	8.49%	19.9	5.7	22.1	23.4	23.2	25.6	33.3	4.1	19.5	20.3	3.8	13.2	13.7
	42.62%	99.9												
			4.9	17.2	18.1	10.8	20.0	22.9	5.8	17.0	18.1	6.4	14.8	15.9
				77.9			69.2			77.2			78.8	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
7.7	17.3	19.0	75.0

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT/UNIT	TARGET WEIGHTING FACTOR	NORMALIZED WEIGHTING FACTOR	HEAT RATE TARGET	ADJUSTED PRIOR HEAT RATE AUG 98 - JUL 99	ADJUSTED PRIOR HEAT RATE AUG 97 - JUL 98	ADJUSTED PRIOR HEAT RATE AUG 96 - JUL 97
GANNON 5	5.37%	9.4	10562	10591	10188	10489
GANNON 6	7.47%	13.0	10507	10479	10540	10476
BIG BEND 1	11.53%	20.1	10143	10366	9998	10343
BIG BEND 2	11.54%	20.1	10071	10200	10027	10201
BIG BEND 3	10.80%	18.8	10017	10234	9910	10140
BIG BEND 4	10.67%	18.6	9976	10110	10012	10041
	57.38%	100.0				
OPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			10160	10296	10078	10251

ORGINAL SHEET NO. 8.401.00E
PAGE 5 OF 35

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2000 - DECEMBER 2000
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET	IMPROVEMENT	SAVINGS	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 GANNON 5	353445.1	353009.8	435.3	2.79%
EA_2 GANNON 6	353445.1	352118.8	1326.3	8.49%
EA_3 BIG BEND 1	353445.1	352125.9	1319.2	8.45%
EA_4 BIG BEND 2	353445.1	352434.8	1010.3	6.47%
EA_5 BIG BEND 3	353445.1	352085.3	1359.8	8.71%
EA_6 BIG BEND 4	353445.1	352241.4	1203.7	7.71%
HEAT RATE				
AHR_1 GANNON 5	353445.1	352606.1	839.0	5.37%
AHR_2 GANNON 6	353445.1	352279.1	1166.0	7.47%
AHR_3 BIG BEND 1	353445.1	351644.1	1801.0	11.53%
AHR_4 BIG BEND 2	353445.1	351643.1	1802.0	11.54%
AHR_5 BIG BEND 3	353445.1	351759.1	1686.0	10.80%
AHR_6 BIG BEND 4	353445.1	351780.1	1665.0	10.67%
TOTAL SAVINGS			15613.6	100.00%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

GANNON 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	435.3	79.3	+10	839.0	10158
+9	391.8	78.9	+9	755.1	10191
+8	348.2	78.5	+8	671.2	10224
+7	304.7	78.1	+7	587.3	10257
+6	261.2	77.7	+6	503.4	10290
+5	217.7	77.3	+5	419.5	10323
+4	174.1	76.9	+4	335.6	10355
+3	130.6	76.5	+3	251.7	10388
+2	87.1	76.1	+2	167.8	10421
+1	43.5	75.7	+1	83.9	10454
				0.0	10487
0	0.0	75.3	0	0.0	10562
				0.0	10637
-1	(109.8)	74.5	-1	(83.9)	10670
-2	(219.7)	73.7	-2	(167.8)	10703
-3	(329.5)	72.8	-3	(251.7)	10736
-4	(439.3)	72.0	-4	(335.6)	10769
-5	(549.2)	71.2	-5	(419.5)	10802
-6	(659.0)	70.4	-6	(503.4)	10834
-7	(768.8)	69.6	-7	(587.3)	10867
-8	(878.6)	68.7	-8	(671.2)	10900
-9	(988.5)	67.9	-9	(755.1)	10933
-10	(1,098.3)	67.1	-10	(839.0)	10966
	Weighting Factor =	2.79%		Weighting Factor =	5.37%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

GANNON 6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,326.3	76.9	+10	1,166.0	10141
+9	1,193.7	76.4	+9	1,049.4	10170
+8	1,061.0	76.0	+8	932.8	10199
+7	928.4	75.5	+7	816.2	10228
+6	795.8	75.0	+6	699.6	10257
+5	663.2	74.6	+5	583.0	10287
+4	530.5	74.1	+4	466.4	10316
+3	397.9	73.6	+3	349.8	10345
+2	265.3	73.1	+2	233.2	10374
+1	132.6	72.7	+1	116.6	10403
				0.0	10432
0	0.0	72.2	0	0.0	10507
				0.0	10582
-1	283.7	71.3	-1	(116.6)	10611
-2	567.4	70.3	-2	(233.2)	10640
-3	851.1	69.4	-3	(349.8)	10669
-4	1,134.8	68.5	-4	(466.4)	10698
-5	1,418.5	67.6	-5	(583.0)	10728
-6	1,702.2	66.6	-6	(699.6)	10757
-7	1,985.9	65.7	-7	(816.2)	10786
-8	2,269.6	64.8	-8	(932.8)	10815
-9	2,553.3	63.8	-9	(1,049.4)	10844
-10	2,837.0	62.9	-10	(1,166.0)	10873
	Weighting Factor =	8.49%		Weighting Factor =	7.47%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,319.2	81.7	+10	1,801.0	9740
+9	1,187.3	81.3	+9	1,620.9	9771
+8	1,055.4	81.0	+8	1,440.8	9802
+7	923.4	80.6	+7	1,260.7	9834
+6	791.5	80.3	+6	1,080.6	9865
+5	659.6	79.9	+5	900.5	9896
+4	527.7	79.5	+4	720.4	9927
+3	395.8	79.2	+3	540.3	9958
+2	263.8	78.8	+2	360.2	9990
+1	131.9	78.5	+1	180.1	10021
				0.0	10052
0	0.0	78.1	0	0.0	10127
				0.0	10202
-1	285.6	77.4	-1	(180.1)	10233
-2	571.2	76.7	-2	(360.2)	10264
-3	856.8	76.0	-3	(540.3)	10296
-4	1,142.4	75.3	-4	(720.4)	10327
-5	1,428.0	74.6	-5	(900.5)	10358
-6	1,713.6	73.9	-6	(1,080.6)	10389
-7	1,999.2	73.2	-7	(1,260.7)	10420
-8	2,284.8	72.5	-8	(1,440.8)	10452
-9	2,570.4	71.8	-9	(1,620.9)	10483
-10	2,856.0	71.1	-10	(1,801.0)	10514
	Weighting Factor =	8.45%		Weighting Factor =	11.53%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,010.3	83.8	+10	1,802.0	9693
+9	909.3	83.5	+9	1,621.8	9722
+8	808.2	83.2	+8	1,441.6	9752
+7	707.2	82.8	+7	1,261.4	9781
+6	606.2	82.5	+6	1,081.2	9810
+5	505.2	82.2	+5	901.0	9840
+4	404.1	81.9	+4	720.8	9869
+3	303.1	81.6	+3	540.6	9898
+2	202.1	81.2	+2	360.4	9927
+1	101.0	80.9	+1	180.2	9957
				0.0	9986
0	0.0	80.6	0	0.0	10061
				0.0	10136
-1	(275.0)	80.0	-1	(180.2)	10165
-2	(550.0)	79.4	-2	(360.4)	10195
-3	(824.9)	78.7	-3	(540.6)	10224
-4	(1,099.9)	78.1	-4	(720.8)	10253
-5	(1,374.9)	77.5	-5	(901.0)	10283
-6	(1,649.9)	76.9	-6	(1,081.2)	10312
-7	(1,924.9)	76.3	-7	(1,261.4)	10341
-8	(2,199.8)	75.6	-8	(1,441.6)	10370
-9	(2,474.8)	75.0	-9	(1,621.8)	10400
-10	(2,749.8)	74.4	-10	(1,802.0)	10429
	Weighting Factor =	6.47%		Weighting Factor =	11.54%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

OCTOBER 2000 - DECEMBER 2000

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,359.8	79.6	+10	1,686.0	9816
+9	1,223.8	79.3	+9	1,517.4	9847
+8	1,087.8	78.9	+8	1,348.8	9877
+7	951.9	78.6	+7	1,180.2	9908
+6	815.9	78.3	+6	1,011.6	9938
+5	679.9	78.0	+5	843.0	9969
+4	543.9	77.6	+4	674.4	10000
+3	407.9	77.3	+3	505.8	10030
+2	272.0	77.0	+2	337.2	10061
+1	136.0	76.6	+1	168.6	10091
				0.0	10122
0	0.0	76.3	0	0.0	10197
				0.0	10272
-1	294.6	75.4	-1	(168.6)	10303
-2	589.2	74.6	-2	(337.2)	10333
-3	883.7	73.7	-3	(505.8)	10364
-4	1,178.3	72.8	-4	(674.4)	10394
-5	1,472.9	72.0	-5	(843.0)	10425
-6	1,767.5	71.1	-6	(1,011.6)	10456
-7	2,062.1	70.2	-7	(1,180.2)	10486
-8	2,356.6	69.3	-8	(1,348.8)	10517
-9	2,651.2	68.5	-9	(1,517.4)	10547
-10	2,945.8	67.6	-10	(1,686.0)	10578
	Weighting Factor =	8.71%		Weighting Factor =	10.80%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2000 - DECEMBER 2000

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($ X 1000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,203.7	87.1	+10	1,665.0	9660
+9	1,083.3	86.8	+9	1,498.5	9684
+8	963.0	86.6	+8	1,332.0	9708
+7	842.6	86.3	+7	1,165.5	9732
+6	722.2	86.0	+6	999.0	9756
+5	601.9	85.8	+5	832.5	9781
+4	481.5	85.5	+4	666.0	9805
+3	361.1	85.2	+3	499.5	9829
+2	240.7	84.9	+2	333.0	9853
+1	120.4	84.7	+1	166.5	9877
				0.0	9901
0	0.0	84.4	0	0.0	9976
				0.0	10051
-1	236.4	83.8	-1	(166.5)	10075
-2	472.9	83.2	-2	(333.0)	10099
-3	709.3	82.7	-3	(499.5)	10123
-4	945.8	82.1	-4	(666.0)	10147
-5	1,182.2	81.5	-5	(832.5)	10172
-6	1,418.6	80.9	-6	(999.0)	10196
-7	1,655.1	80.3	-7	(1,165.5)	10220
-8	1,891.5	79.8	-8	(1,332.0)	10244
-9	2,128.0	79.2	-9	(1,498.5)	10268
-10	2,364.4	78.6	-10	(1,665.0)	10292
	Weighting Factor =	7.71%		Weighting Factor =	10.67%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 5	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	79.8	79.9	28.4	77.2	79.8	79.9	79.8	79.8	79.9	79.7	79.9	79.8	75.3
2. POF	0.0	0.0	64.5	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
3. EUOF	20.2	20.1	7.1	19.5	20.2	20.1	20.2	20.2	20.1	20.3	20.1	20.2	19.0
4. EUOR	20.2	20.1	20.1	20.1	20.2	20.1	20.2	20.2	20.1	20.3	20.1	20.2	20.2
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	666	623	236	624	666	645	666	666	645	666	645	666	7414
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	78	73	508	95	78	75	78	78	75	79	75	78	1370
9. POH	0	0	480	24	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	126	118	45	118	126	122	126	126	122	127	122	126	1404
11. MOH & EMOH	24	22	8	22	24	23	24	24	23	24	23	24	265
12. OPER BTU (GBTU)	796.599	717.819	339.438	1145.187	1189.238	1210.604	1282.557	1295.477	1221.876	1190.575	1066.387	925.913	12381.670
13. NET GEN (MWH)	75304	67630	32285	109917	113300	114241	119704	121038	115341	112647	102367	88508	1172282
14. ANOHR (BTU/KWH)	10578	10614	10514	10419	10496	10597	10714	10703	10594	10569	10417	10461	10562
15. NOF (%)	46.7	44.9	56.5	75.9	73.3	76.3	77.5	78.3	77.1	69.9	65.6	54.9	66.7
16. NPC (MW)	242	242	242	232	232	232	232	232	232	242	242	242	237

17. ANOHR EQUATION ANOHR = NOF(-12.3085) + 11383

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DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00L
PAGE 13 OF 35

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 6	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	61.3	39.5	72.2
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	48.4	5.7
3. EUOF	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	18.7	12.1	22.1
4. EUOR	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	619	579	619	599	619	599	619	619	599	619	479	319	6888
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	125	117	125	120	125	121	125	125	121	126	241	425	1896
9. POH	0	0	0	0	0	0	0	0	0	0	144	360	504
10. FOH & EFOH	138	129	138	133	138	133	138	138	133	138	107	71	1532
11. MOH & EMOH	37	34	37	35	37	35	37	37	35	37	28	19	406
12. OPER BTU (GBTU)	1265.540	1145.843	1494.213	1762.542	1789.503	1805.333	1936.202	1959.355	1837.494	1790.074	1292.431	754.665	18833.195
13. NET GEN (MWH)	119596	107904	142302	169859	171130	171710	183145	185538	174850	170071	124139	72168	1792412
14. ANOHR (BTU/KWH)	10582	10619	10500	10377	10457	10514	10572	10560	10509	10525	10411	10457	10507
15. NOF (%)	49.3	47.5	58.6	76.2	74.3	77.1	79.5	80.6	78.5	70.1	66.1	57.7	68.1
16. NPC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382

17. ANOHR EQUATION ANOHR = NOF(-4.1530) + 10790

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PAGE 14 OF 35

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	82.9	82.9	82.9	27.7	80.1	82.8	82.9	82.9	82.8	83.0	82.8	82.9	78.1
2. POF	0.0	0.0	0.0	66.8	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
3. EUOF	17.1	17.1	17.1	5.6	16.7	17.2	17.1	17.1	17.2	17.0	17.2	17.1	16.1
4. EUOR	17.1	17.1	17.1	16.7	17.2	17.2	17.1	17.1	17.2	17.0	17.2	17.1	17.1
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	681	637	681	220	659	659	681	681	659	681	659	681	7576
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	63	59	63	499	85	61	63	63	61	64	61	63	1208
9. POH	0	0	0	480	24	0	0	0	0	0	0	0	504
10. FOH & EFOH	73	68	73	23	71	71	73	73	71	73	71	73	813
11. MOH & EMOH	54	51	54	17	53	53	54	54	53	54	53	54	604
12. OPER BTU (GBTU)	2379.136	2213.676	2464.893	850.594	2488.664	2506.135	2620.572	2627.553	2512.050	2588.579	2424.124	2461.600	28137.576
13. NET GEN (MWH)	237167	220790	244689	84080	245400	246653	255824	256491	247225	254592	240482	245191	2778584
14. ANOHR (BTU/KWH)	10031	10026	10074	10116	10141	10161	10244	10244	10161	10168	10080	10040	10127
15. NOF (%)	81.8	81.3	84.4	91.9	89.6	90.0	90.3	90.6	90.2	87.8	85.7	84.5	87.1
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421

17. ANOHR EQUATION ANOHR = NOF(-15.0564) + 11438

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ORGINAL SHEET NO. 8.401.00E
PAGE 15 OF 35

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	84.8	84.8	54.7	65.1	84.8	84.7	84.8	84.8	84.7	84.8	84.7	84.8	80.6
2. POF	0.0	0.0	35.5	23.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
3. EUOF	15.2	15.2	9.8	11.5	15.2	15.3	15.2	15.2	15.3	15.2	15.3	15.2	14.5
4. EUOR	15.2	15.2	15.2	15.1	15.2	15.3	15.2	15.2	15.3	15.2	15.3	15.2	15.2
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	687	643	443	510	687	666	687	687	666	687	666	687	7717
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	57	53	301	209	57	54	57	57	54	58	54	57	1067
9. POH	0	0	284	168	0	0	0	0	0	0	0	0	432
10. FOH & EFOH	72	68	47	53	72	70	72	72	70	72	70	72	810
11. MOH & EMOH	41	38	26	30	41	40	41	41	40	41	40	41	460
12. OPER BTU (GBTU)	2516.683	2327.790	1682.096	2018.659	2678.461	2620.133	2728.241	2732.189	2625.950	2669.290	2573.913	2583.866	29757.271
13. NET GEN (MWH)	250081	231269	167419	201433	267004	260372	270053	270442	260963	265565	256302	256863	2957766
14. ANOHR (BTU/KWH)	10063	10065	10047	10021	10032	10063	10103	10103	10063	10051	10043	10059	10061
15. NOF (%)	85.4	84.4	88.7	94.9	93.4	94.0	94.5	94.6	94.2	90.7	90.4	87.7	91.0
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
17. ANOHR EQUATION	ANOHR = NOF(-9.9261) + 10964												

FILED:
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DOCKET NO. : 000001-EI
ORDER NO.:

ORIGINAL SHEET NO. 8.401.00E
PAGE 16 OF 35

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	80.9	80.9	80.9	61.9	80.9	81.0	80.9	80.9	81.0	52.3	72.8	80.9	76.3
2. POF	0.0	0.0	0.0	23.4	0.0	0.0	0.0	0.0	0.0	35.4	10.0	0.0	5.7
3. EUOF	19.1	19.1	19.1	14.7	19.1	19.0	19.1	19.1	19.0	12.2	17.2	19.1	18.0
4. EUOR	19.1	19.1	19.1	19.2	19.1	19.0	19.1	19.1	19.0	18.9	19.1	19.1	19.1
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	674	630	674	499	674	651	674	674	651	434	586	674	7493
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	70	66	70	220	70	69	70	70	69	311	134	70	1291
9. POH	0	0	0	168	0	0	0	0	0	264	72	0	504
10. FOH & EFOH	98	92	98	73	98	95	98	98	95	63	86	98	1092
11. MOH & EMOH	44	41	44	33	44	42	44	44	42	28	38	44	488
12. OPER BTU (GBTU)	2156.942	1969.206	2325.700	1930.015	2449.947	2445.045	2583.309	2609.699	2466.075	1607.054	2095.705	2319.015	26957.712
13. NET GEN (MWH)	211445	192868	228681	189798	241539	240058	250813	253471	242205	158499	206306	227936	2643619
14. ANOHR (BTU/KWH)	10201	10210	10170	10169	10143	10185	10300	10296	10182	10139	10158	10174	10197
15. NOF (%)	70.9	69.1	76.6	87.8	82.8	85.1	86.0	86.9	85.9	82.4	79.4	76.4	80.6
16. NPC (MW)	443	443	443	433	433	433	433	433	433	443	443	443	438

17. ANOHR EQUATION ANOHR = NOF(-35.3936) + 13050

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	86.0	86.1	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	66.0	86.0	84.4
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	1.9
3. EUOF	14.0	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	10.7	14.0	13.7
4. EUOR	14.0	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	13.9	14.0	14.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	692	648	692	670	692	670	692	692	670	692	514	692	8015
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	52	48	52	49	52	50	52	52	50	53	206	52	769
9. POH	0	0	0	0	0	0	0	0	0	0	168	0	168
10. FOH & EFOH	51	48	51	50	51	50	51	51	50	51	38	51	593
11. MOH & EMOH	53	49	53	51	53	51	53	53	51	53	39	53	612
12. OPER BTU (GBTU)	2544.336	2345.807	2652.833	2728.142	2799.322	2710.990	2840.177	2848.734	2718.153	2724.971	2025.136	2626.818	31565.419
13. NET GEN (MWH)	255907	235801	266288	275403	282013	270748	281803	282650	271475	273794	203590	264509	3163981
14. ANOHR (BTU/KWH)	9942	9948	9962	9906	9926	10013	10079	10079	10013	9953	9947	9931	9976
15. NOF (%)	82.7	81.4	86.1	93.0	92.2	91.4	92.1	92.4	91.7	88.5	88.6	85.5	88.7
16. NPC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445

17. ANOHR EQUATION ANOHR = NOF(-24.0193) + 12107

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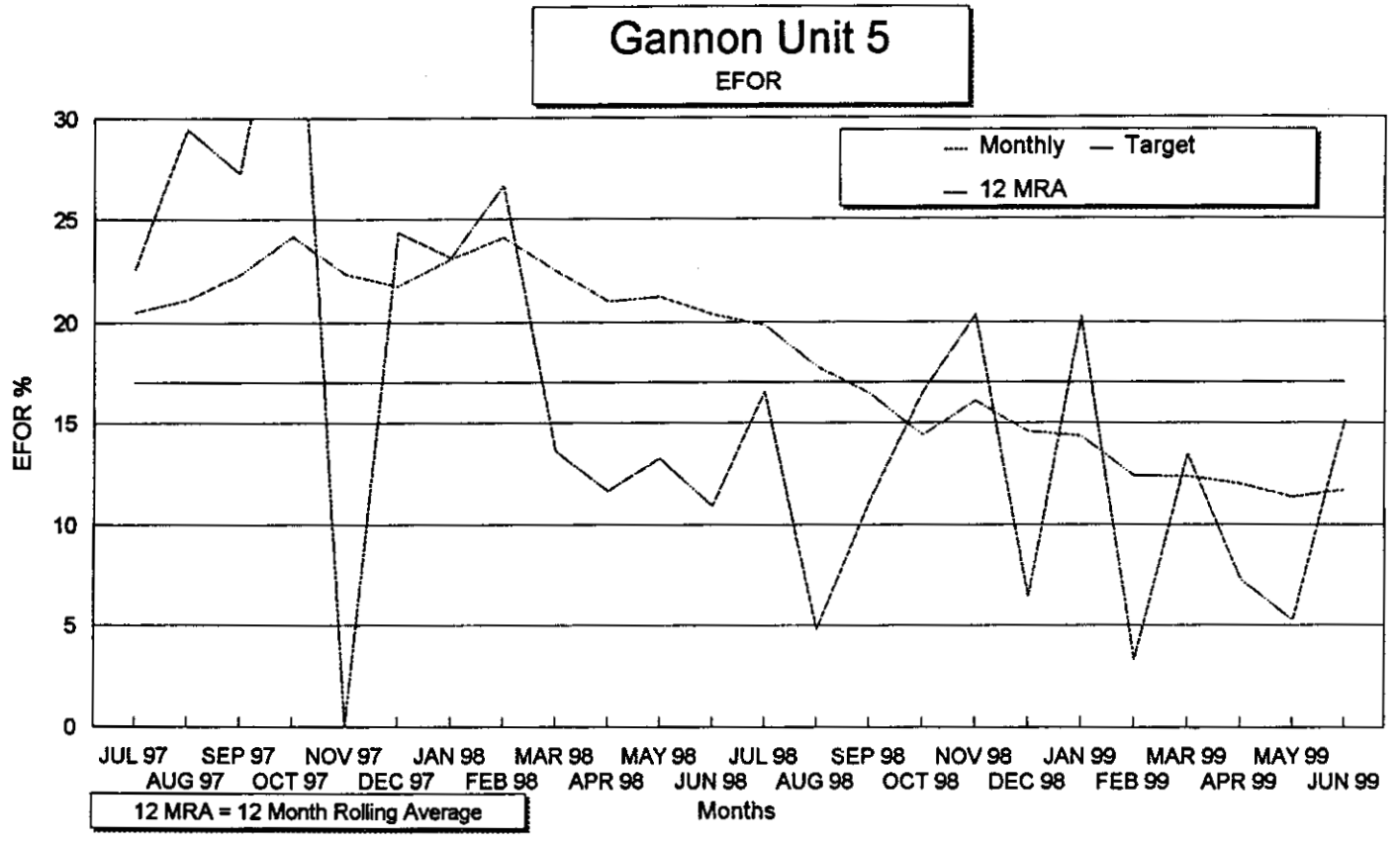
ORGINAL SHEET NO. 8.401.00E
PAGE 18 OF 35

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2000 - DECEMBER 2000

	PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DISCRIPTION
+	BIG BEND 1	APR 11 - MAY 01	FUEL SYSTEM CLEAN-UP
+	BIG BEND 2	MAR 21 - APR 07	FUEL SYSTEM CLEAN-UP
+	BIG BEND 3	APR 04 - APR 10	FUEL SYSTEM CLEAN-UP
+	BIG BEND 3	OCT 21 - NOV 03	APH BASKET REPLACEMENT
+	BIG BEND 4	NOV 06 - NOV 12	FUEL SYSTEM CLEAN-UP
+	GANNON 5	MAR 12 - APR 01	FUEL SYSTEM CLEAN-UP
	GANNON 6	NOV 25 - DEC 15	FUEL SYSTEM CLEAN-UP SLAG TANK REPAIRS STACK EXTENSION

+ **CPM WAS NOT INCLUDED FOR THIS UNIT, OUTAGE IS LESS THAN 4 WEEKS**

Note; All GPIF units have less than 4 weeks of planned outage therefore, no CPM were required.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EFOR
Monthly
Target
12 MRA
EFOR %
30
25
20
15
10
5
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OCT 97
NOV 97
DEC 97
JAN 98
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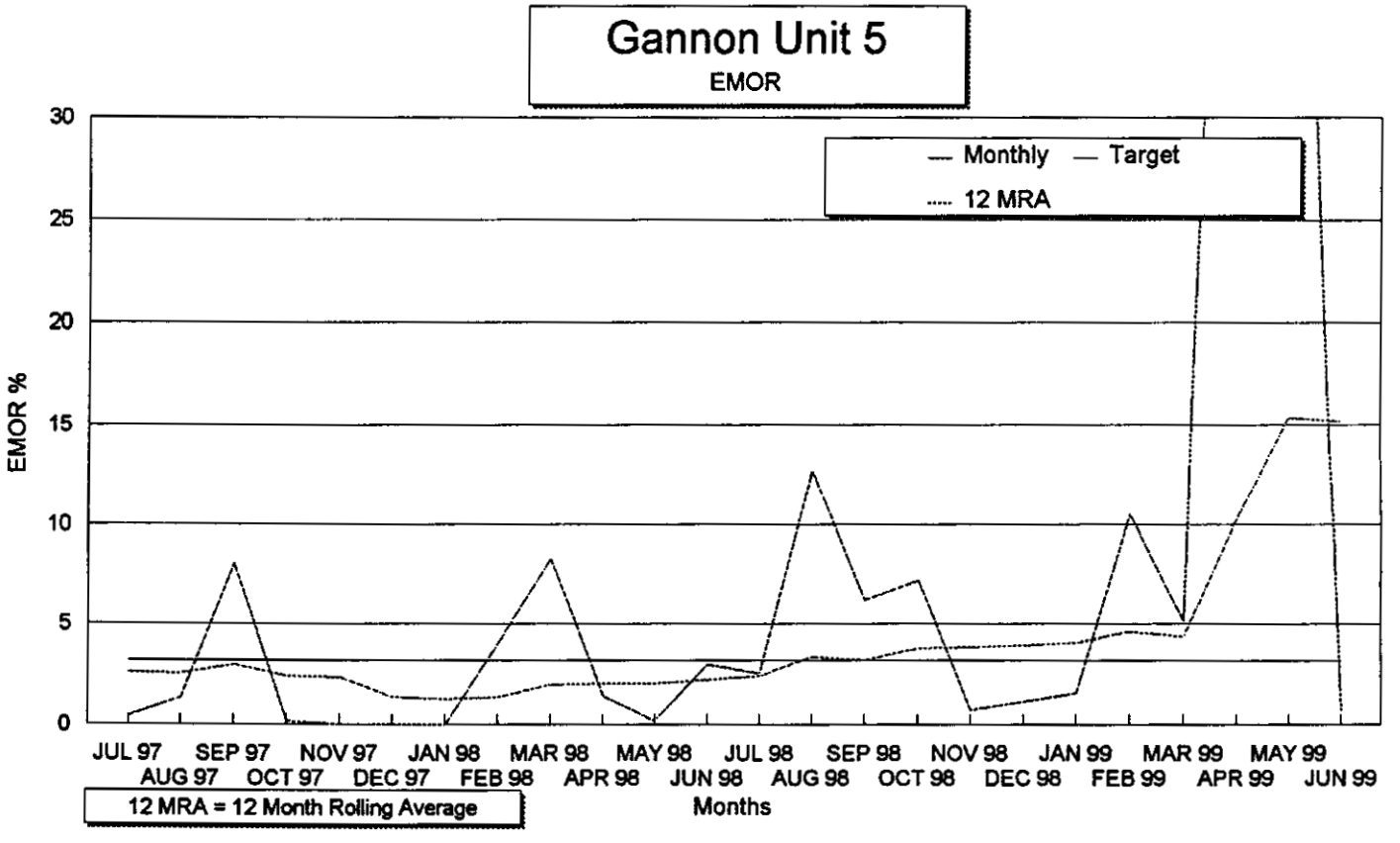
12 MRA = 12 Month Rolling Average
Months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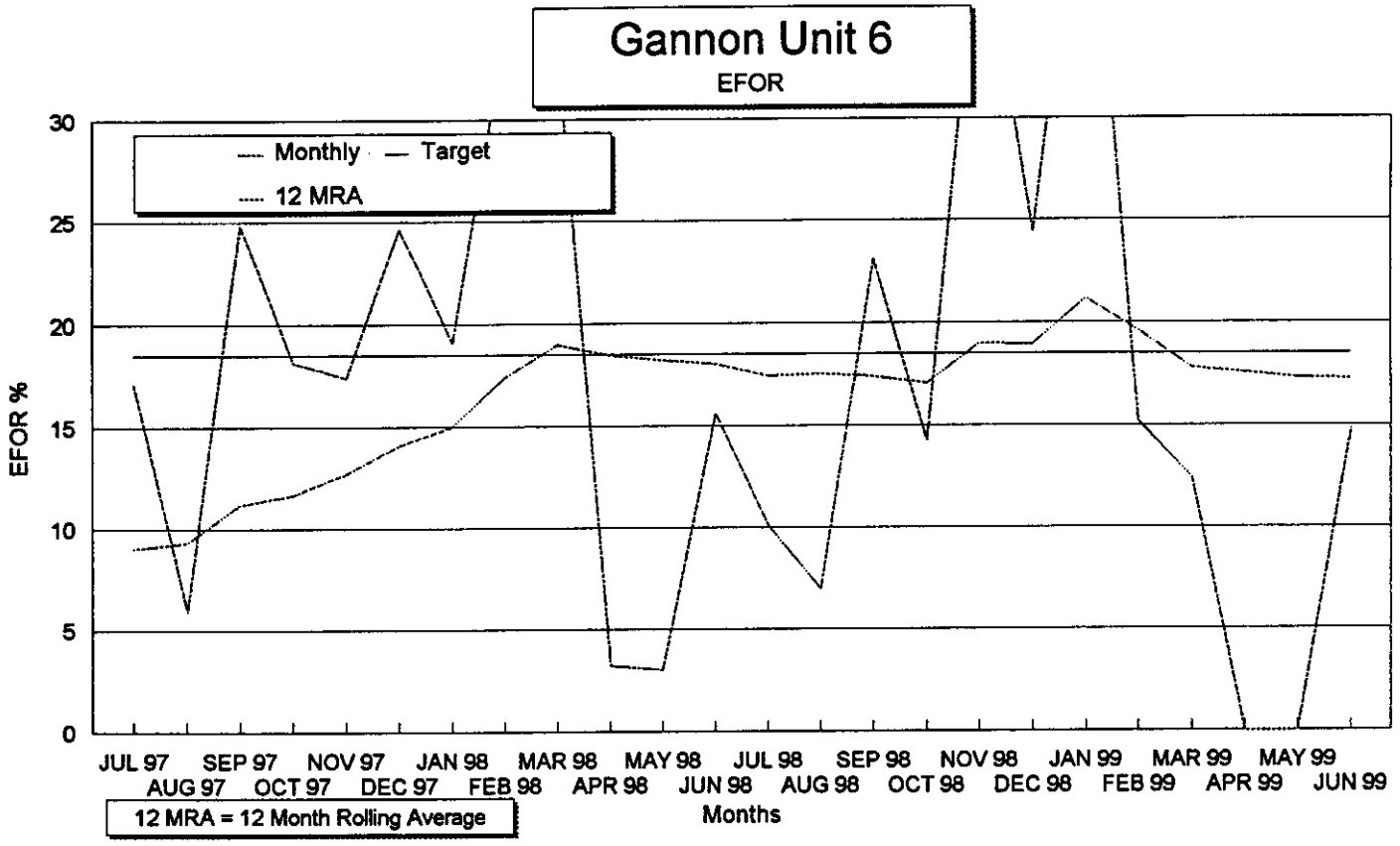
12 MRA = 12 Month Rolling Average
Months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SEP 97
OCT 97
NOV 97
DEC 97
JAN 98
FEB 98
MAR 98
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MAY 98
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AUG 98
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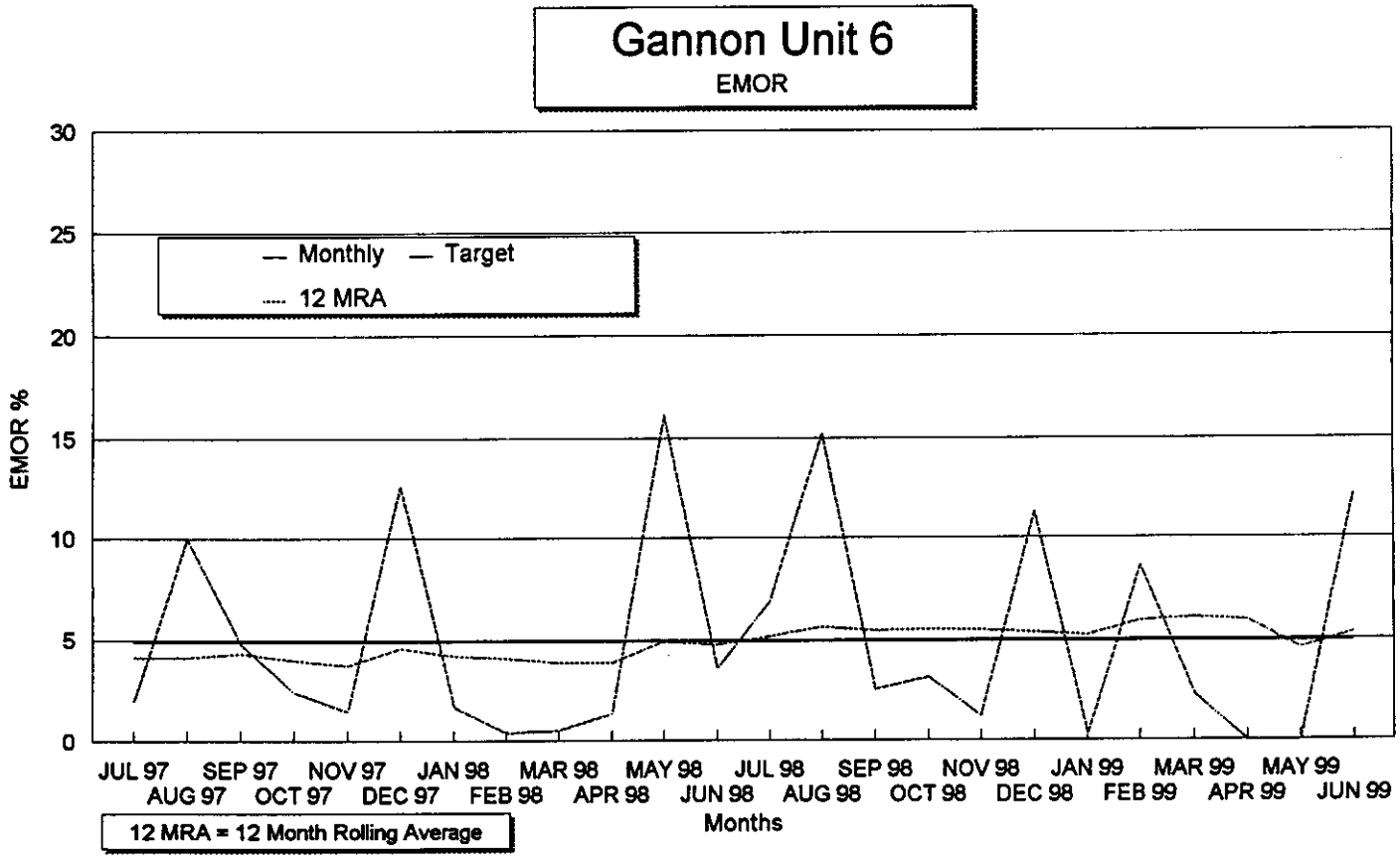
Months
12 MRA = 12 Month Rolling Average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SEP 97
OCT 97
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DEC 97
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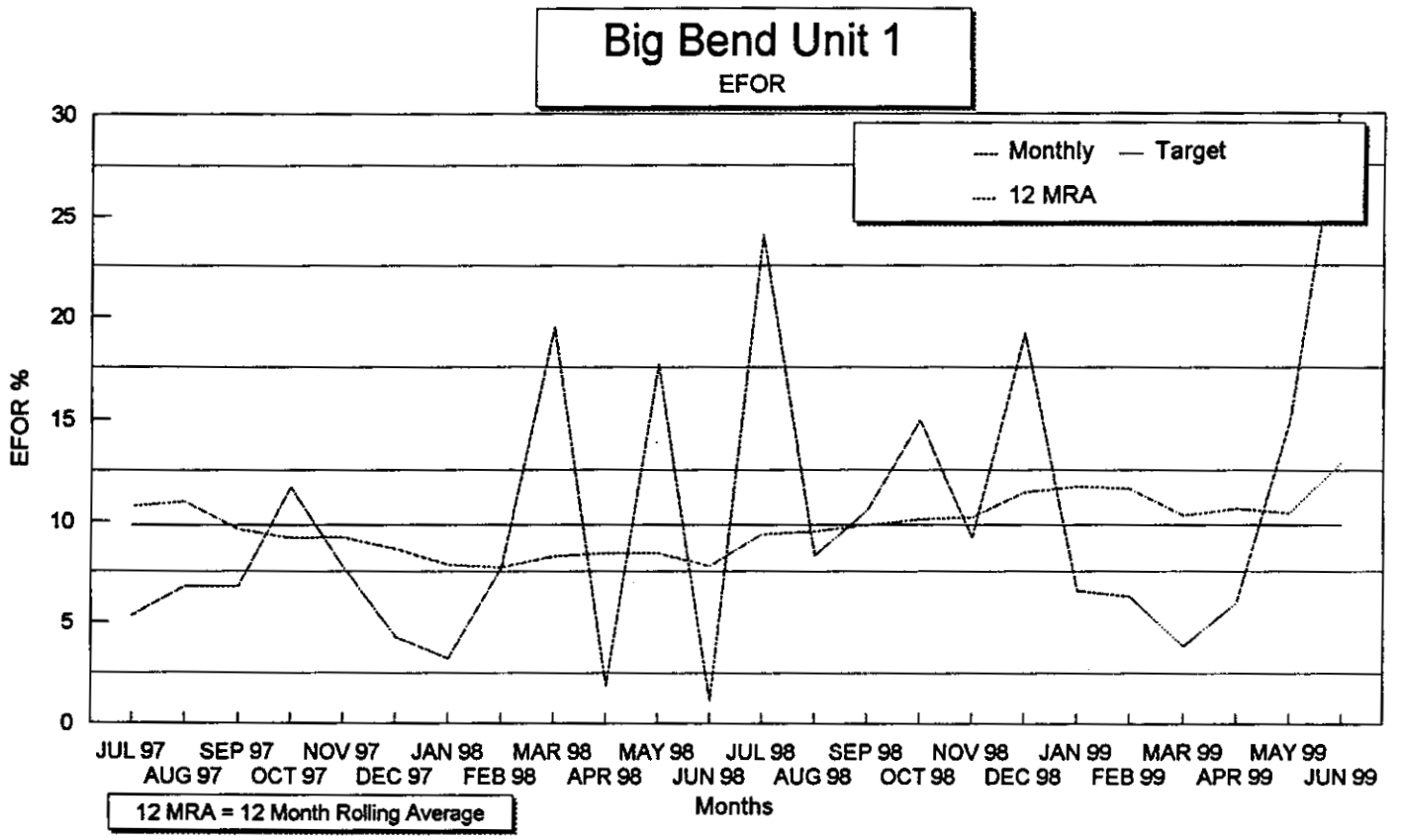
Months
12 MRA = 12 Month Rolling Average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Target
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EFOR %
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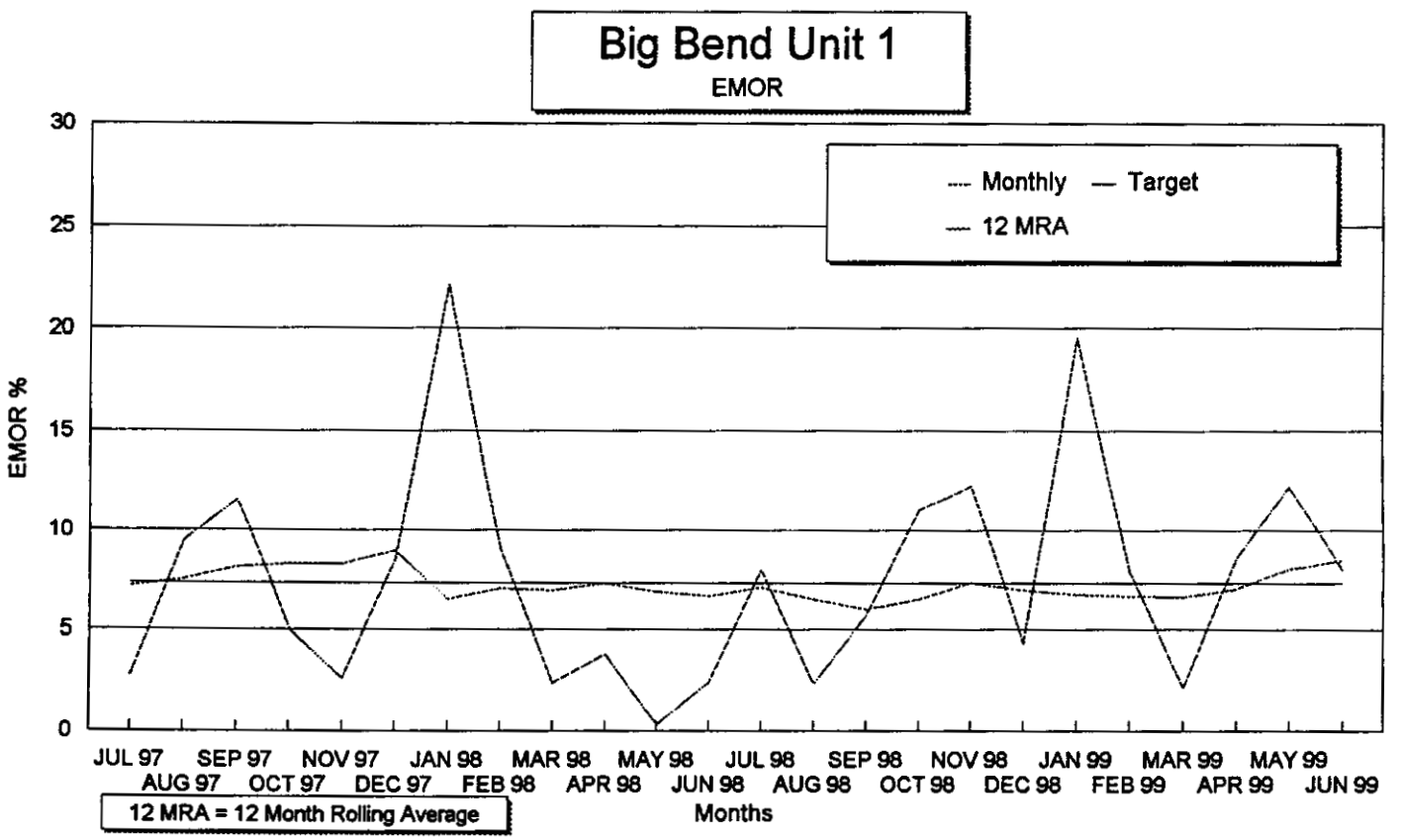
12 MRA = 12 Month Rolling Average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Target
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FEB 98
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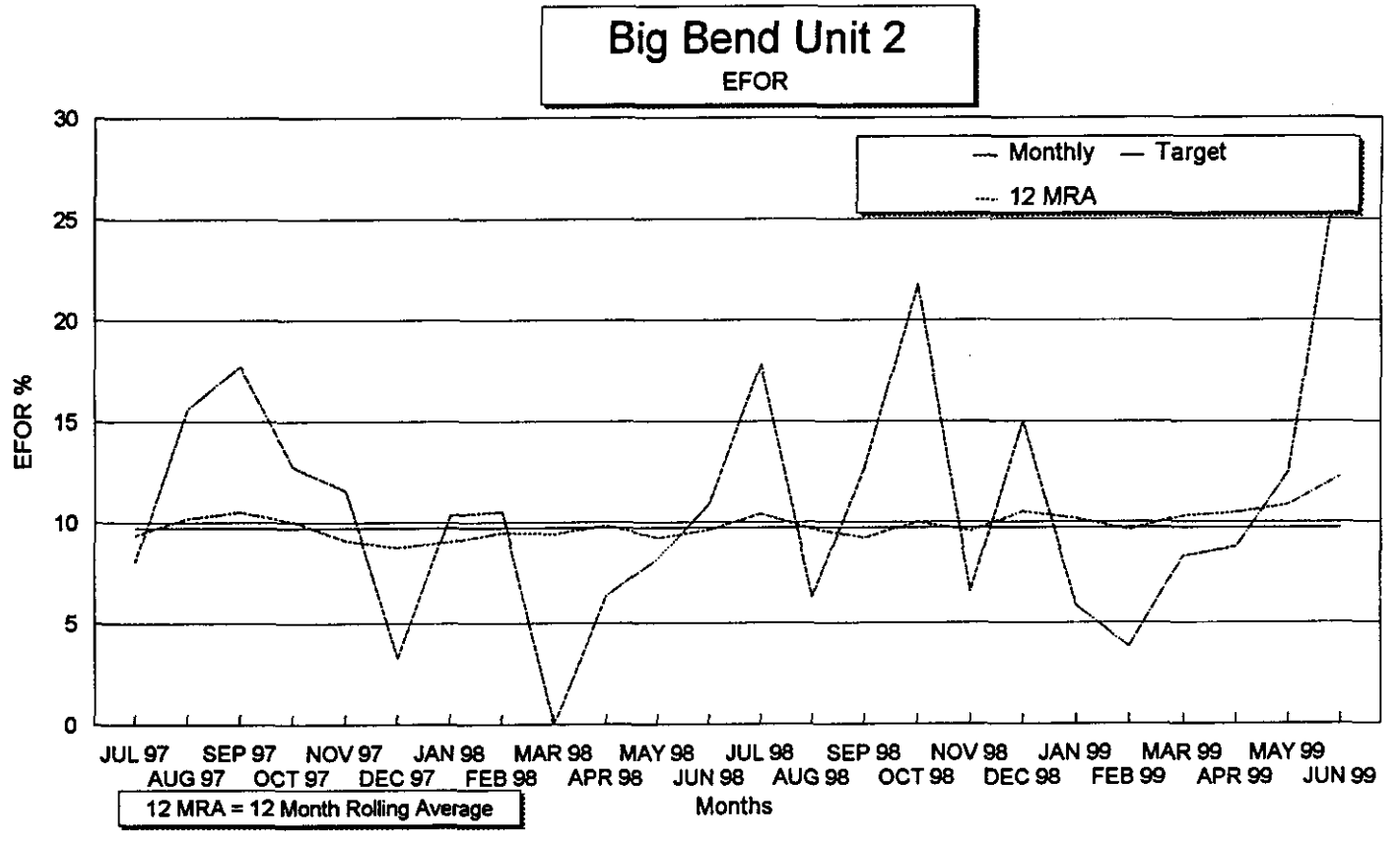
12 MRA = 12 Month Rolling Average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Monthly
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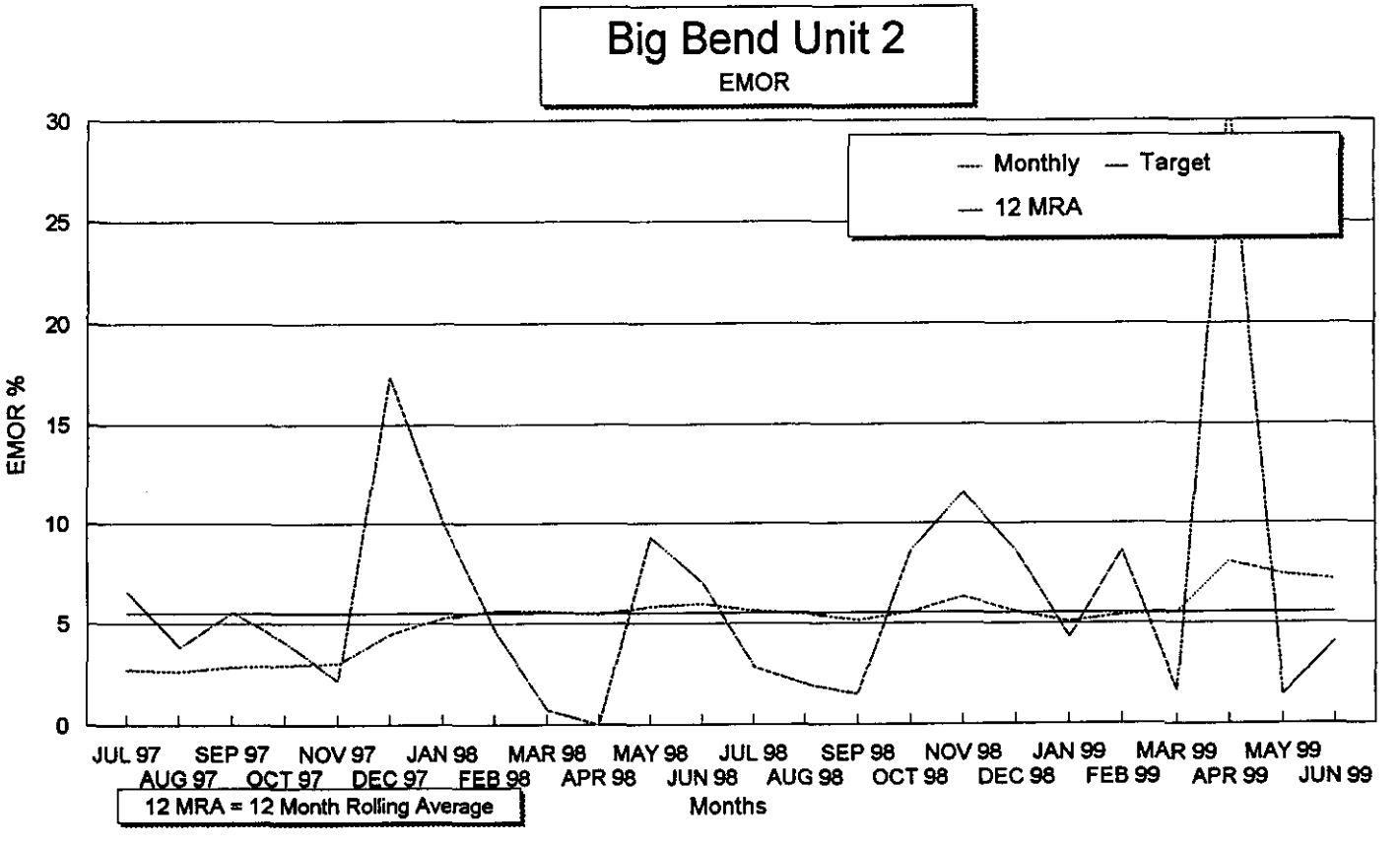
Months
12 MRA = 12 Month Rolling Average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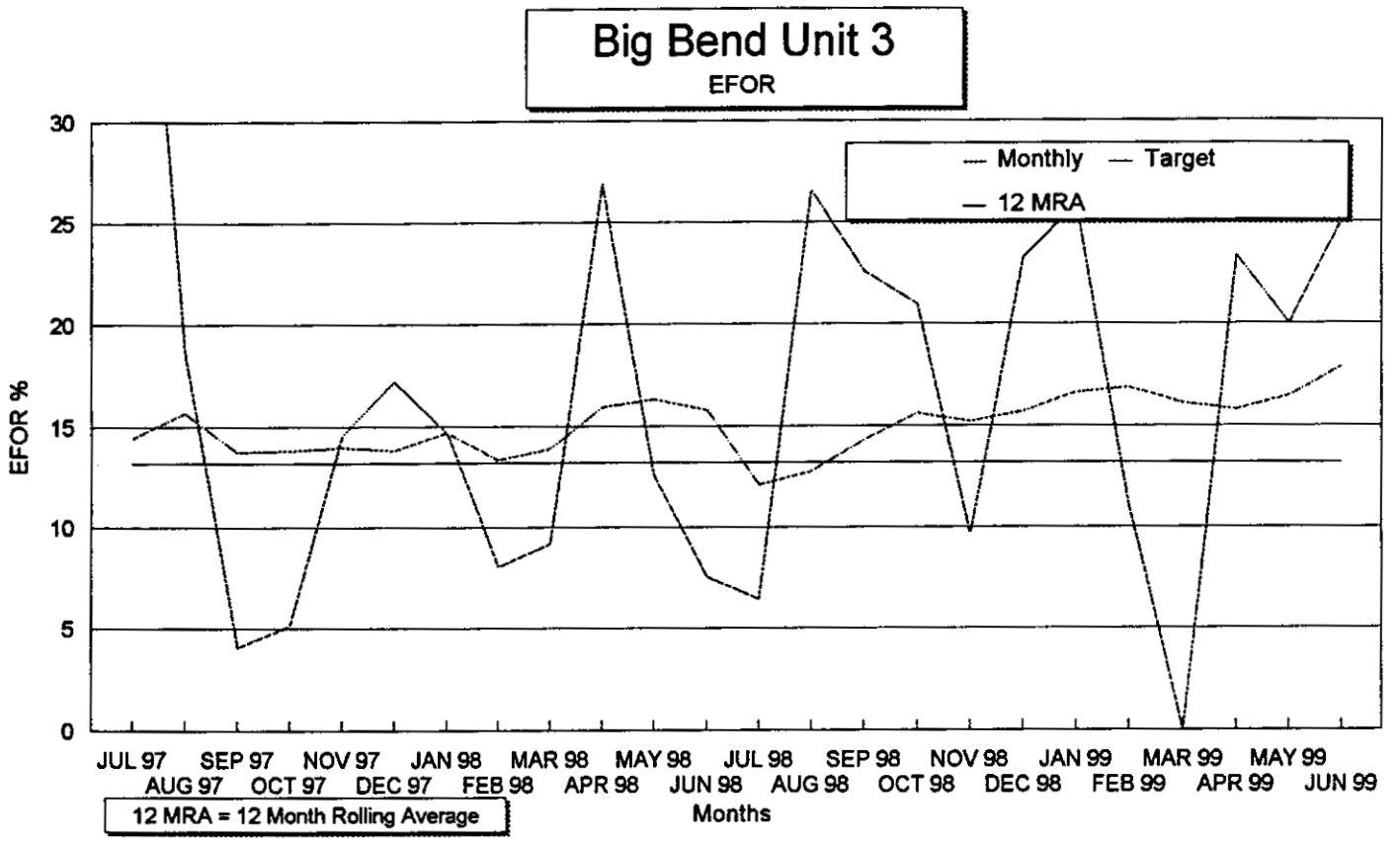
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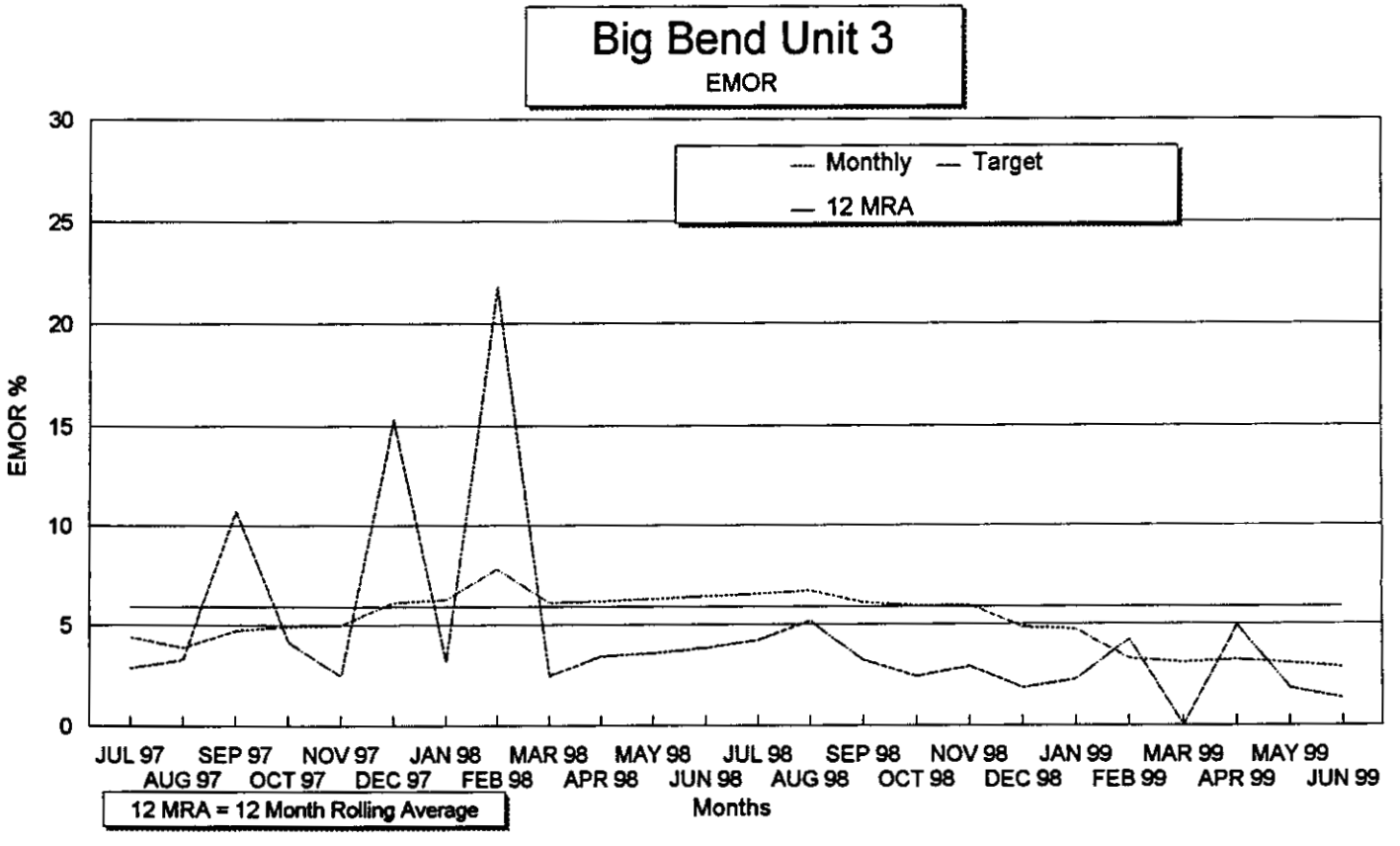
12 MRA = 12 Month Rolling Average
Months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EMOR %
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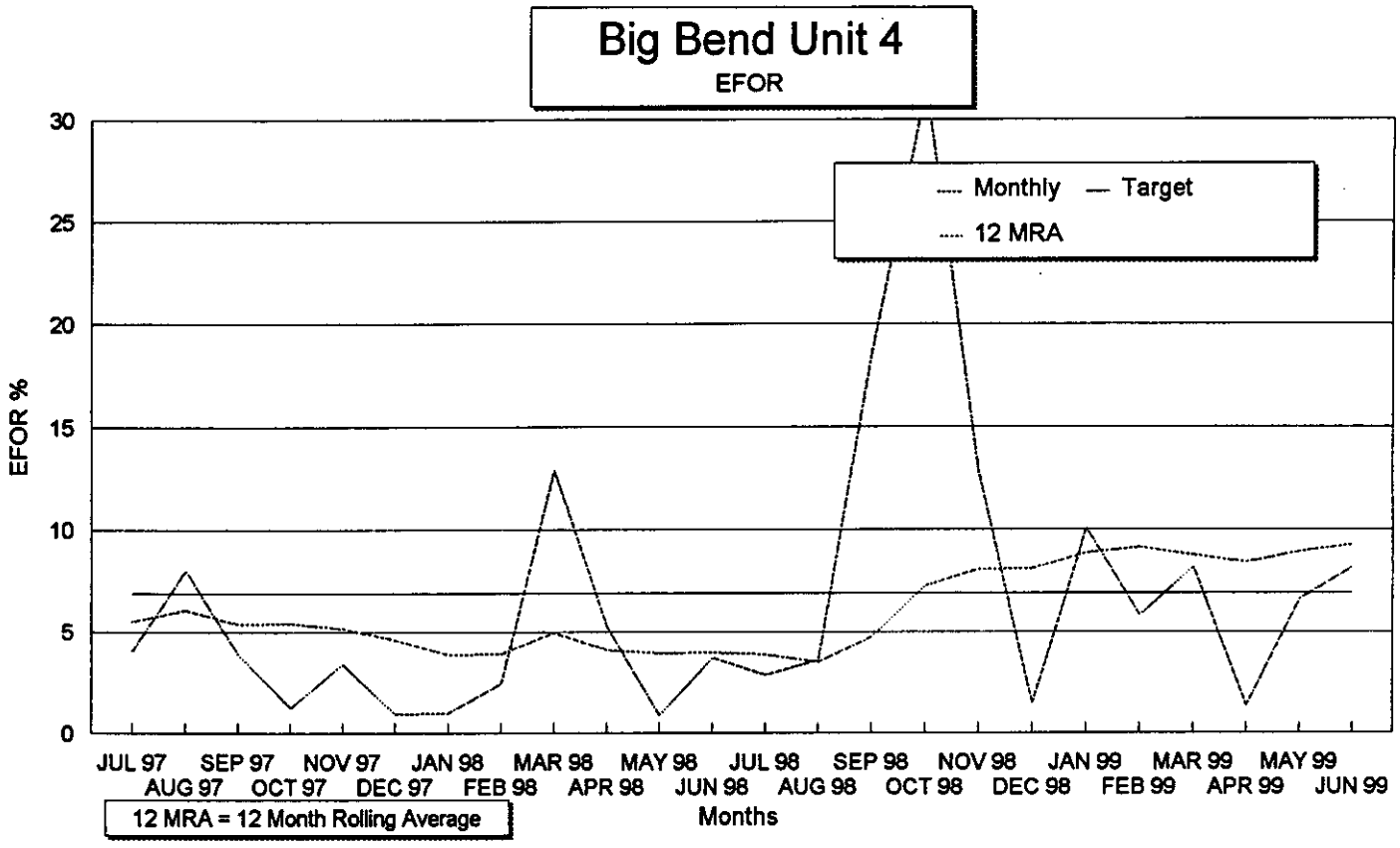
Months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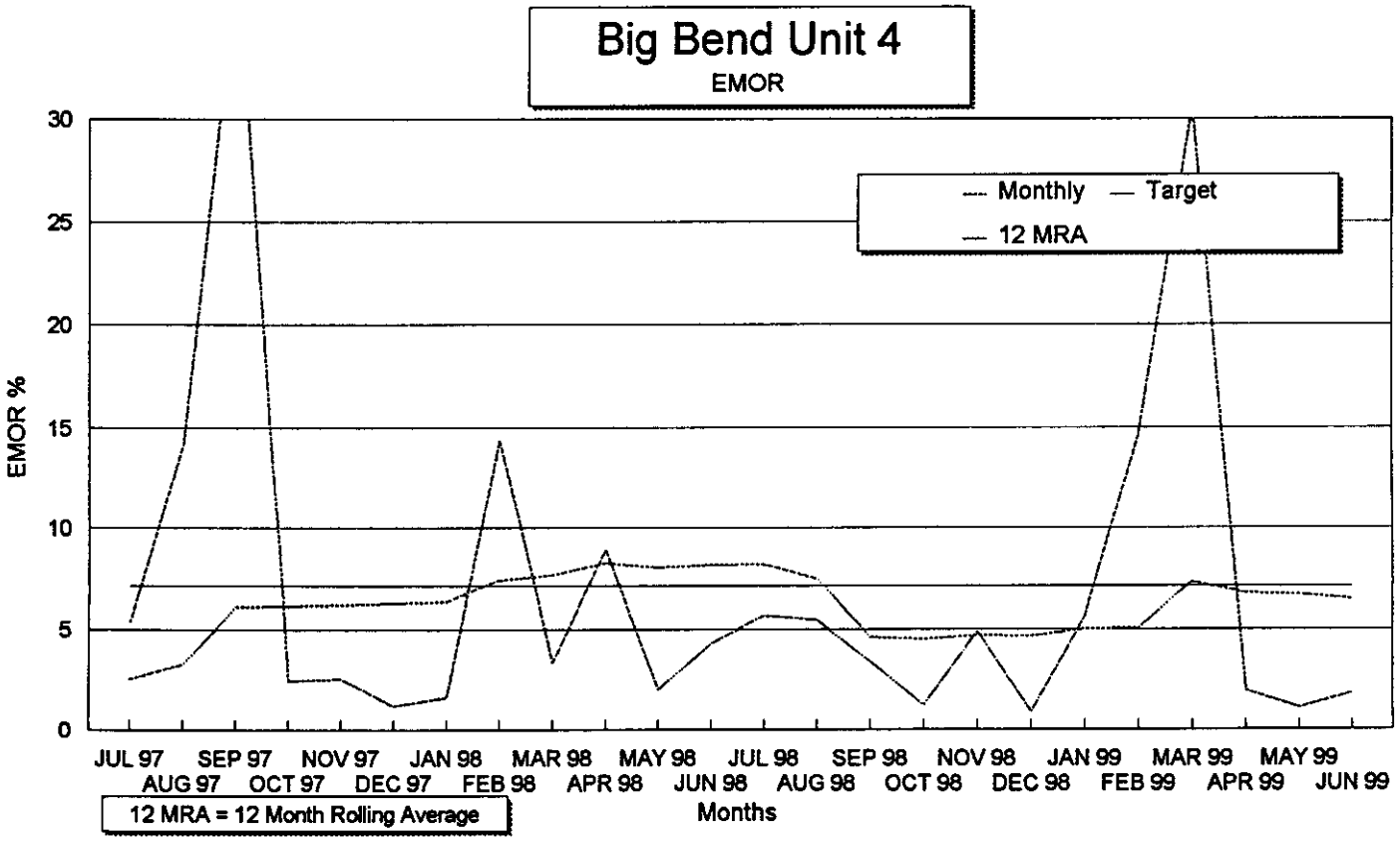
Big Bend Unit 4
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DEC 98
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MAR 99
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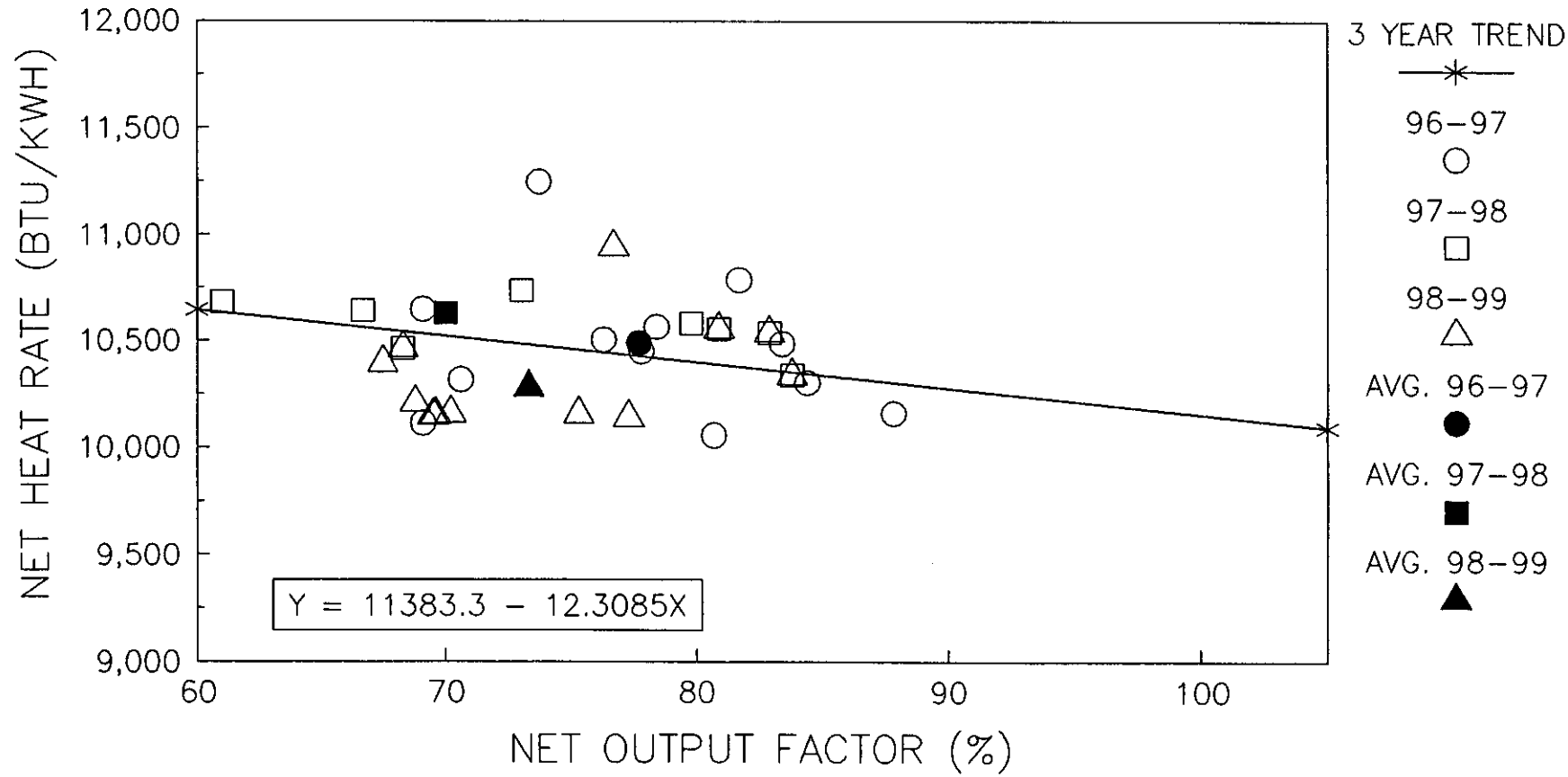
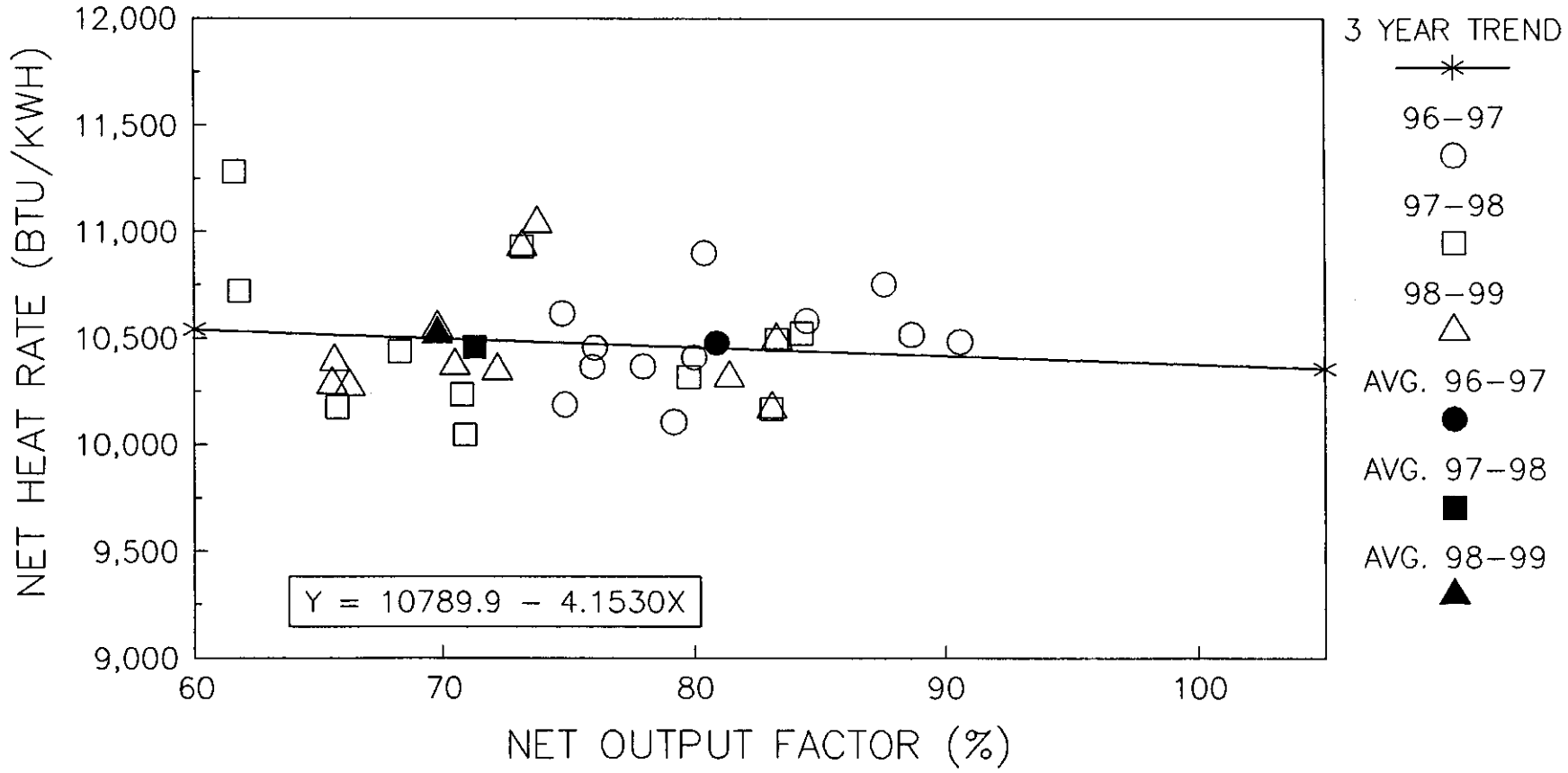
Months
12 MRA = 12 Month Rolling Average

TAMPA ELECTRIC COMPANY
HEAT RATE VS. NET OUTPUT FACTOR
GANNON 5, ANNUAL 2000



TARGET NET HEAT RATE: 10562
TARGET NET OUTPUT FACTOR: 66.7%

TAMPA ELECTRIC COMPANY
HEAT RATE VS. NET OUTPUT FACTOR
GANNON 6, ANNUAL 2000

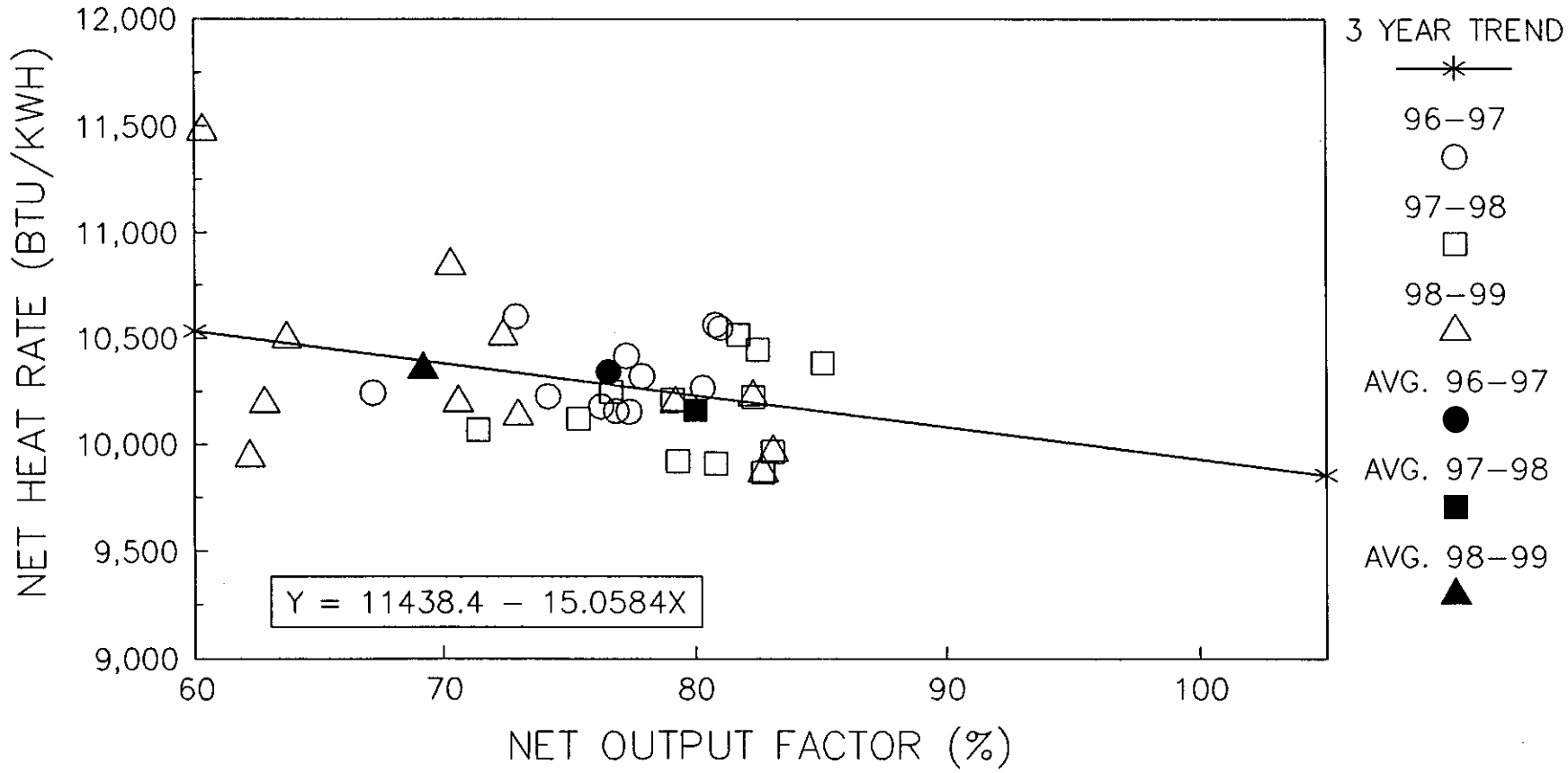


TARGET NET HEAT RATE: 10507
TARGET NET OUTPUT FACTOR: 68.1%

TAMPA ELECTRIC COMPANY

HEAT RATE VS. NET OUTPUT FACTOR

BIG BEND 1, ANNUAL 2000

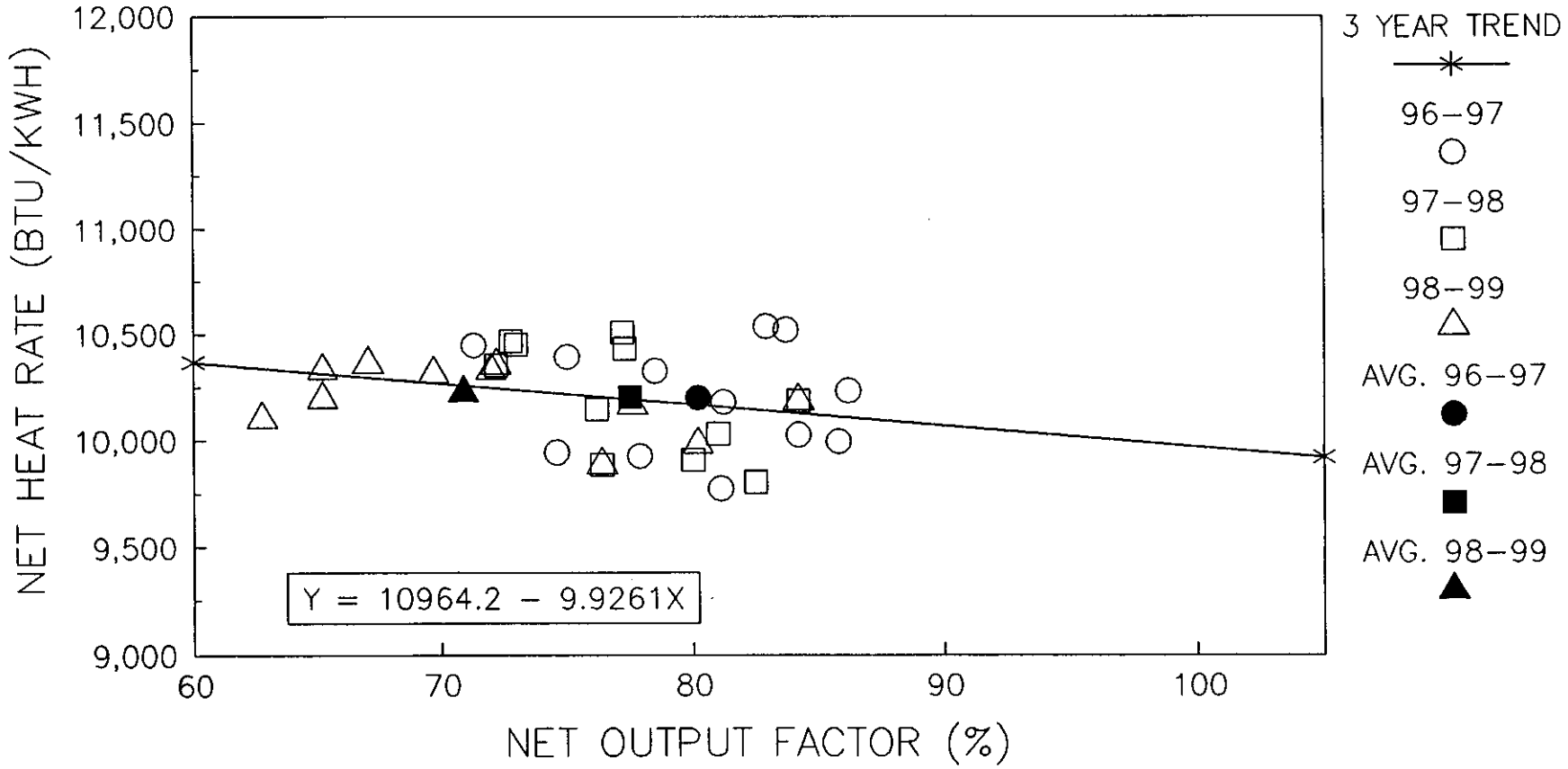


TARGET NET HEAT RATE: 10127
TARGET NET OUTPUT FACTOR: 87.1%

TAMPA ELECTRIC COMPANY

HEAT RATE VS. NET OUTPUT FACTOR

BIG BEND 2, ANNUAL 2000

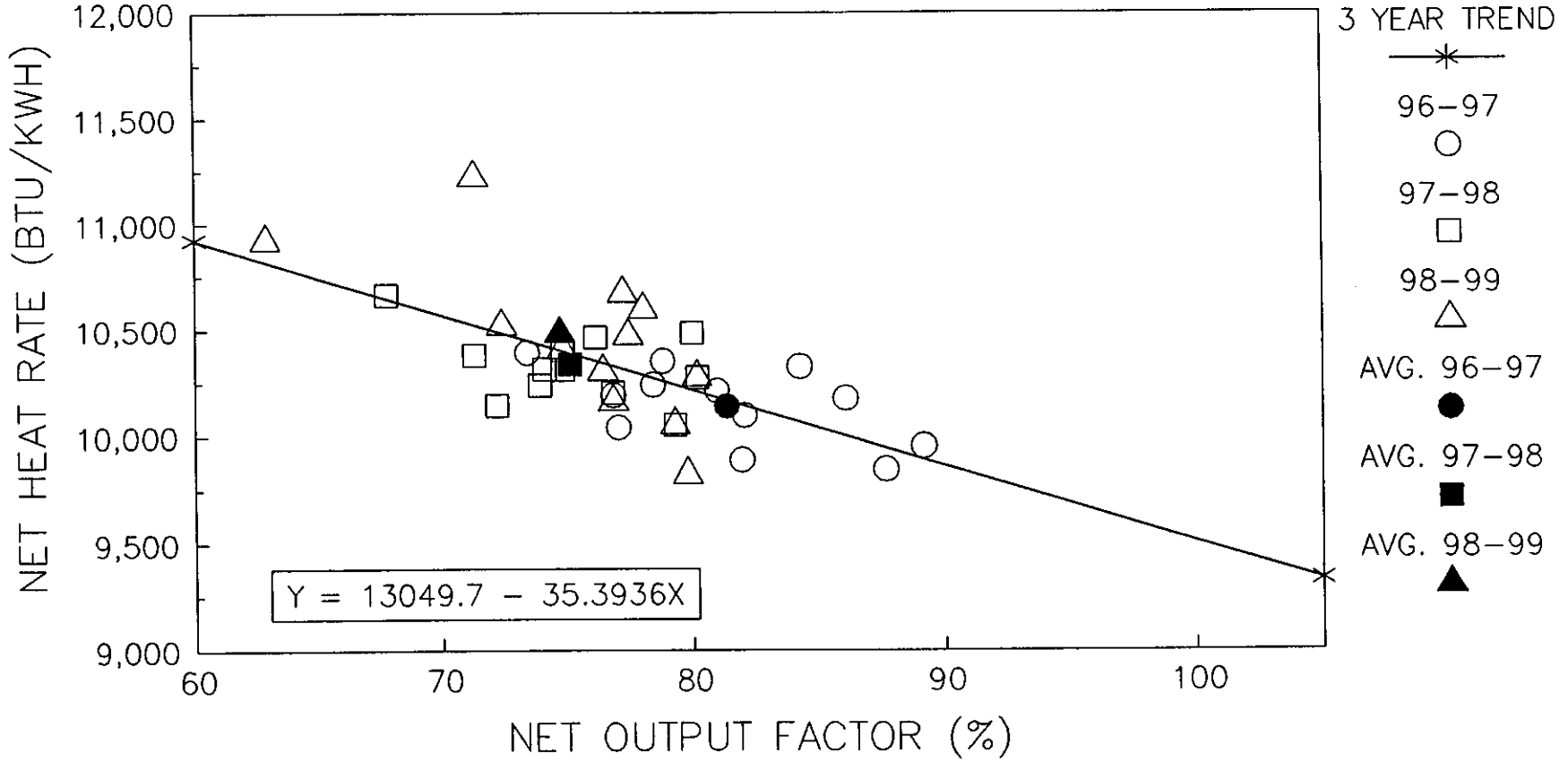


TARGET NET HEAT RATE: 10061
TARGET NET OUTPUT FACTOR: 91.0%

TAMPA ELECTRIC COMPANY

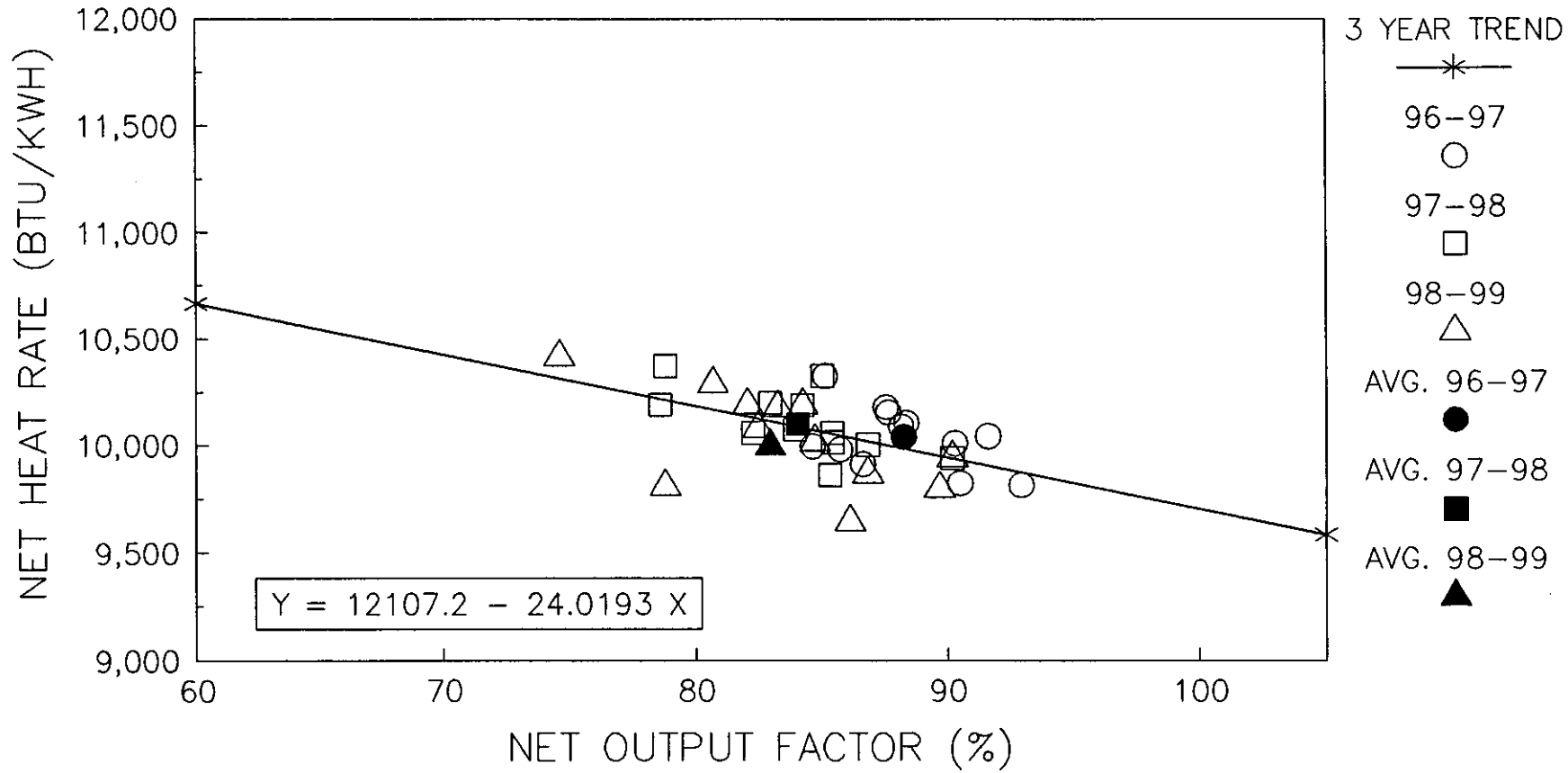
HEAT RATE VS. NET OUTPUT FACTOR

BIG BEND 3, ANNUAL 2000



TARGET NET HEAT RATE: 10197
TARGET NET OUTPUT FACTOR: 80.6%

TAMPA ELECTRIC COMPANY
HEAT RATE VS. NET OUTPUT FACTOR
BIG BEND 4, ANNUAL 2000



TARGET NET HEAT RATE: 9976
TARGET NET OUTPUT FACTOR: 88.7%

TAMPA ELECTRIC COMPANY
TABLE 4.2
GENERATING UNITS IN GPIF
JANUARY 2000 - DECEMBER 2000

UNIT		MDC GROSS (MW)	NDC NET (MW)
GANNON 5		255	242
GANNON 6		405	392
BIG BEND 1		445	426
BIG BEND 2		445	426
BIG BEND 3		460	443
BIG BEND 4		475	447
	TOTAL	2485	2376
	SYSTEM TOTAL	3847	3629
	% OF SYSTEM TOTAL	64.60%	65.47%

TAMPA ELECTRIC COMPANY
UNITS RATINGS
JANUARY 2000 - DECEMBER 2000

UNIT		MDC GROSS (MW)	NDC NET (MW)
HOOKERS POINT 1		33	32
HOOKERS POINT 2		33	32
HOOKERS POINT 3		33	32
HOOKERS POINT 4		43	41
HOOKERS POINT 5		70	67
	HOOKERS TOTAL	212	204
GANNON 1		120	114
GANNON 2		120	113
GANNON 3		165	155
GANNON 4		200	189
GANNON 5		255	242
GANNON 6		405	392
	GANNON TOTAL	1265	1205
BIG BEND 1		445	426
BIG BEND 2		445	426
BIG BEND 3		460	443
BIG BEND 4		475	447
	BIG BEND TOTAL	1825	1742
GANNON CT		17	17
BIG BEND CT1		17	17
BIG BEND CT2		80	80
BIG BEND CT3		80	80
	CT TOTAL	194	194
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK		315	250
	SYSTEM TOTAL	3847	3629

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2000 - DECEMBER 2000

STATION	UNIT	NET OUTPUT MWH	% OF PROJECTED OUTPUT	% CUMULATIVE PROJECTED OUTPUT
BIG BEND	4	3,163,981	17.69%	17.69%
BIG BEND	2	2,957,766	16.54%	34.23%
BIG BEND	1	2,778,584	15.54%	49.77%
BIG BEND	3	2,643,619	14.78%	64.55%
GANNON	6	1,792,412	10.02%	74.58%
POLK		1,609,565	9.00%	83.58%
GANNON	5	1,172,282	6.56%	90.13%
GANNON	4	557,875	3.12%	93.25%
GANNON	3	449,785	2.52%	95.77%
GANNON	1	293,476	1.64%	97.41%
GANNON	2	239,020	1.34%	98.75%
HOOKERS POINT	5	54,104	0.30%	99.05%
HOOKERS POINT	4	36,930	0.21%	99.25%
HOOKERS POINT	3	35,394	0.20%	99.45%
HOOKERS POINT	1	27,928	0.16%	99.61%
HOOKERS POINT	2	16,843	0.09%	99.70%
PHILLIPS	1	16,460	0.09%	99.80%
PHILLIPS	2	16,279	0.09%	99.89%
BIG BEND CT	3	10,239	0.06%	99.94%
BIG BEND CT	2	6,479	0.04%	99.98%
BIG BEND CT	1	1,821	0.01%	99.99%
GANNON CT	1	1,825	0.01%	100.00%
TOTAL GENERATION		17,882,667	100.00%	

GENERATION BY COAL UNITS:	17,658,365	MWH
% GENERATION BY COAL UNITS:	98.75%	
GENERATION BY OIL UNITS:	224,302	MWH
% GENERATION BY OIL UNITS:	1.25%	
GENERATION BY GPIF UNITS:	14,508,644	MWH
% GENERATION BY GPIF UNITS:	81.13%	

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2000 - DECEMBER 2000
TABLE OF CONTENTS

SCHEDULE	PAGE
BIG BEND 1 - ESTIMATED UNIT PERFORMANCE DATA	2
BIG BEND 2 - ESTIMATED UNIT PERFORMANCE DATA	3
BIG BEND 3 - ESTIMATED UNIT PERFORMANCE DATA	4
BIG BEND 4 - ESTIMATED UNIT PERFORMANCE DATA	5
GANNON 1 - ESTIMATED UNIT PERFORMANCE DATA	6
GANNON 2 - ESTIMATED UNIT PERFORMANCE DATA	7
GANNON 3 - ESTIMATED UNIT PERFORMANCE DATA	8
GANNON 4 - ESTIMATED UNIT PERFORMANCE DATA	9
GANNON 5 - ESTIMATED UNIT PERFORMANCE DATA	10
GANNON 6 - ESTIMATED UNIT PERFORMANCE DATA	11
HOOKERS POINT 1 - ESTIMATED UNIT PERFORMANCE DATA	12
HOOKERS POINT 2 - ESTIMATED UNIT PERFORMANCE DATA	13
HOOKERS POINT 3 - ESTIMATED UNIT PERFORMANCE DATA	14
HOOKERS POINT 4 - ESTIMATED UNIT PERFORMANCE DATA	15
HOOKERS POINT 5 - ESTIMATED UNIT PERFORMANCE DATA	16
GANNON CT1 - ESTIMATED UNIT PERFORMANCE DATA	17
BIG BEND CT1 - ESTIMATED UNIT PERFORMANCE DATA	18
BIG BEND CT2 - ESTIMATED UNIT PERFORMANCE DATA	19
BIG BEND CT3 - ESTIMATED UNIT PERFORMANCE DATA	20
PHILLIPS 1 - ESTIMATED UNIT PERFORMANCE DATA	21
PHILLIPS 2 - ESTIMATED UNIT PERFORMANCE DATA	22
POLK - ESTIMATED UNIT PERFORMANCE DATA	23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	82.9	82.9	82.9	27.7	80.1	82.8	82.9	82.9	82.8	83.0	82.8	82.9	78.1
2. POF	0.0	0.0	0.0	66.8	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
3. EUOF	17.1	17.1	17.1	5.6	16.7	17.2	17.1	17.1	17.2	17.0	17.2	17.1	16.1
4. EUOR	17.1	17.1	17.1	16.7	17.2	17.2	17.1	17.1	17.2	17.0	17.2	17.1	17.1
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	681	637	681	220	659	659	681	681	659	681	659	681	7576
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	63	59	63	499	85	61	63	63	61	64	61	63	1208
9. POH	0	0	0	480	24	0	0	0	0	0	0	0	504
10. FOH & EFOH	73	68	73	23	71	71	73	73	71	73	71	73	813
11. MOH & EMOH	54	51	54	17	53	53	54	54	53	54	53	54	604
12. OPER BTU (GBTU)	2379.136	2213.676	2464.893	850.594	2488.664	2506.135	2620.572	2627.553	2512.050	2588.579	2424.124	2461.600	28137.576
13. NET GEN (MWH)	237167	220790	244689	84080	245400	246653	255824	256491	247225	254592	240482	245191	2778584
14. ANOHR (BTU/KWH)	10031	10026	10074	10116	10141	10161	10244	10244	10161	10168	10080	10040	10127
15. NOF (%)	81.8	81.3	84.4	91.9	89.6	90.0	90.3	90.6	90.2	87.8	85.7	84.5	87.1
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421
17. ANOHR EQUATION	ANOHR = NOF(-15.0564) + 11438												

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PAGE 2 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	84.8	84.8	54.7	65.1	84.8	84.7	84.8	84.8	84.7	84.8	84.7	84.8	80.6
2. POF	0.0	0.0	35.5	23.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
3. EUOF	15.2	15.2	9.8	11.5	15.2	15.3	15.2	15.2	15.3	15.2	15.3	15.2	14.5
4. EUOR	15.2	15.2	15.2	15.1	15.2	15.3	15.2	15.2	15.3	15.2	15.3	15.2	15.2
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	687	643	443	510	687	666	687	687	666	687	666	687	7717
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	57	53	301	209	57	54	57	57	54	58	54	57	1067
9. POH	0	0	264	168	0	0	0	0	0	0	0	0	432
10. FOH & EFOH	72	68	47	53	72	70	72	72	70	72	70	72	810
11. MOH & EMOH	41	38	26	30	41	40	41	41	40	41	40	41	460
12. OPER BTU (GBTU)	2516.683	2327.790	1682.096	2018.659	2678.461	2620.133	2728.241	2732.189	2625.950	2669.290	2573.913	2583.866	29757.271
13. NET GEN (MWH)	250081	231269	167419	201433	267004	260372	270053	270442	260963	265565	256302	256863	2957766
14. ANOHR (BTU/KWH)	10063	10065	10047	10021	10032	10063	10103	10103	10063	10051	10043	10059	10061
15. NOF (%)	85.4	84.4	88.7	94.9	93.4	94.0	94.5	94.6	94.2	90.7	90.4	87.7	91.0
16. NPC (MW)	426	426	426	416	416	416	416	416	416	426	426	426	421

17. ANOHR EQUATION ANOHR = NOF(-9.9261) + 10964

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PAGE 3 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	80.9	80.9	80.9	61.9	80.9	81.0	80.9	80.9	81.0	52.3	72.8	80.9	76.3
2. POF	0.0	0.0	0.0	23.4	0.0	0.0	0.0	0.0	0.0	35.4	10.0	0.0	5.7
3. EUOF	19.1	19.1	19.1	14.7	19.1	19.0	19.1	19.1	19.0	12.2	17.2	19.1	18.0
4. EUOR	19.1	19.1	19.1	19.2	19.1	19.0	19.1	19.1	19.0	18.9	19.1	19.1	19.1
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	674	630	674	499	674	651	674	674	651	434	586	674	7493
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	70	66	70	220	70	69	70	70	69	311	134	70	1291
9. POH	0	0	0	168	0	0	0	0	0	264	72	0	504
10. FOH & EFOH	98	92	98	73	98	95	98	98	95	63	86	98	1092
11. MOH & EMOH	44	41	44	33	44	42	44	44	42	28	38	44	488
12. OPER BTU (GBTU)	2156.942	1969.206	2325.700	1930.015	2449.947	2445.045	2583.309	2609.699	2466.075	1607.054	2095.705	2319.015	26957.712
13. NET GEN (MWH)	211445	192868	228681	189798	241539	240058	250813	253471	242205	158499	206306	227936	2643619
14. ANOHR (BTU/KWH)	10201	10210	10170	10169	10143	10185	10300	10296	10182	10139	10158	10174	10197
15. NOF (%)	70.9	69.1	76.6	87.8	82.8	85.1	86.0	86.9	85.9	82.4	79.4	76.4	80.6
16. NPC (MW)	443	443	443	433	433	433	433	433	433	443	443	443	438
17. ANOHR EQUATION	ANOHR = NOF(-35.3936) + 13050												

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PAGE 4 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	86.0	86.1	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	66.0	86.0	84.4
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.3	0.0	1.9
3. EUOF	14.0	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	10.7	14.0	13.7
4. EUOR	14.0	13.9	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	13.9	14.0	14.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	692	648	692	670	692	670	692	692	670	692	514	692	8015
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	52	48	52	49	52	50	52	52	50	53	206	52	769
9. POH	0	0	0	0	0	0	0	0	0	0	168	0	168
10. FOH & EFOH	51	48	51	50	51	50	51	51	50	51	38	51	593
11. MOH & EMOH	53	49	53	51	53	51	53	53	51	53	39	53	612
12. OPER BTU (GBTU)	2544.336	2345.807	2652.833	2728.142	2799.322	2710.990	2840.177	2848.734	2718.153	2724.971	2025.136	2626.818	31565.419
13. NET GEN (MWH)	255907	235801	266288	275403	282013	270748	281803	282650	271475	273794	203590	264509	3163981
14. ANOHR (BTU/KWH)	9942	9948	9962	9906	9926	10013	10079	10079	10013	9953	9947	9931	9976
15. NOF (%)	82.7	81.4	86.1	93.0	92.2	91.4	92.1	92.4	91.7	88.5	88.6	85.5	88.7
16. NPC (MW)	447	447	447	442	442	442	442	442	442	447	447	447	445

17. ANOHR EQUATION ANOHR = NOF(-24.0193) + 12107

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PAGE 5 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	80.1	80.3	80.1	80.1	80.1	80.1	80.1	80.1	58.9	46.6	80.1	80.1	75.5
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.7	41.9	0.0	0.0	5.7
3. EUOF	19.9	19.7	19.9	19.9	19.9	19.9	19.9	19.9	14.4	11.5	19.9	19.9	18.7
4. EUOR	19.9	19.7	19.9	19.9	19.9	19.9	19.9	19.9	19.7	19.9	19.9	19.9	19.9
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	440	411	453	231	232	220	295	293	205	173	232	448	3633
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	304	285	291	488	512	500	449	451	515	572	488	296	5151
9. POH	0	0	0	0	0	0	0	0	192	312	0	0	504
10. FOH & EFOH	112	104	112	108	112	108	112	112	79	65	108	112	1244
11. MOH & EMOH	36	33	36	35	36	35	36	36	25	21	35	36	400
12. OPER BTU (GBTU)	276.308	254.721	356.445	272.181	294.380	282.540	355.118	353.793	251.303	212.371	268.721	317.166	3495.047
13. NET GEN (MWH)	22260	20472	29748	23825	23617	22294	30639	30530	21858	18560	23565	26108	293476
14. ANOHR (BTU/KWH)	12413	12442	11982	11424	12465	12673	11590	11588	11497	11442	11403	12148	11909
15. NOF (%)	44.4	43.7	57.6	90.5	89.3	88.9	91.1	91.4	93.5	94.1	89.1	51.1	70.9
16. NPC (MW)	114	114	114	114	114	114	114	114	114	114	114	114	114

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PAGE 6 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	79.6	79.5	79.6	2.5	0.0	79.4	79.6	79.6	79.4	79.6	79.4	79.6	66.5
2. POF	0.0	0.0	0.0	96.8	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4
3. EUOF	20.4	20.5	20.4	0.7	0.0	20.6	20.4	20.4	20.6	20.4	20.6	20.4	17.1
4. EUOR	20.4	20.5	20.4	21.7	0.0	20.6	20.4	20.4	20.6	20.4	20.6	20.4	20.5
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	450	420	453	9	0	261	264	262	262	267	171	455	3274
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	294	276	291	710	744	459	480	482	458	478	549	289	5510
9. POH	0	0	0	696	744	0	0	0	0	0	0	0	1440
10. FOH & EFOH	115	108	115	4	0	112	115	115	112	115	112	115	1138
11. MOH & EMOH	37	35	37	1	0	36	37	37	36	37	36	37	366
12. OPER BTU (GBTU)	265.167	245.728	318.309	8.869	0.000	326.314	345.078	341.079	341.501	339.587	206.887	317.738	3056.257
13. NET GEN (MWH)	20033	18525	24521	732	0	25836	26904	26594	27041	27339	16941	24554	239020
14. ANOHR (BTU/KWH)	13237	13265	12981	12116	0	12630	12826	12825	12629	12421	12212	12940	12787
15. NOF (%)	39.4	39.0	47.9	72.0	0.0	87.6	90.2	89.8	91.3	90.6	87.7	47.8	64.6
16. NPC (MW)	113	113	113	113	113	113	113	113	113	113	113	113	113

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DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 7 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	86.0	56.5	55.5	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	81.1
2. POF	0.0	34.5	35.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
3. EUOF	14.0	9.1	9.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	13.2
4. EUOR	14.0	13.8	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	437	270	285	327	268	308	330	332	303	334	282	449	3925
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	307	426	459	392	476	412	414	412	417	411	438	295	4859
9. POH	0	240	264	0	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	61	37	39	59	61	59	61	61	59	61	59	61	678
11. MOH & EMOH	43	26	28	42	43	42	43	43	42	43	42	43	480
12. OPER BTU (GBTU)	416.339	254.109	333.423	498.707	397.047	465.788	507.041	508.088	461.748	530.027	422.536	484.119	5278.972
13. NET GEN (MWH)	33948	20664	27973	43158	34317	40134	43549	43627	39827	45699	36616	40273	449785
14. ANOHR (BTU/KWH)	12264	12297	11919	11555	11570	11606	11643	11646	11594	11598	11540	12021	11737
15. NOF (%)	50.1	49.4	63.3	91.0	88.3	89.9	91.0	90.6	90.6	88.3	83.8	57.9	76.4
16. NPC (MW)	155	155	155	145	145	145	145	145	145	155	155	155	150

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	78.8	78.7	78.8	78.9	78.8	78.9	78.8	78.8	78.9	33.0	15.7	78.8	42.8
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.0	80.0	0.0	45.6
3. EUOF	21.2	21.3	21.2	21.1	21.2	21.1	21.2	21.2	21.1	9.0	4.3	21.2	11.6
4. EUOR	21.2	21.3	21.2	21.1	21.2	21.1	21.2	21.2	21.1	21.4	21.5	21.2	21.3
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	2209
6. SH	453	419	469	383	405	355	373	377	354	153	54	468	675
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	291	277	275	336	339	365	371	367	366	592	666	276	1534
9. POH	0	0	0	0	0	0	0	0	0	432	576	0	1008
10. FOH & EFOH	113	106	113	109	113	109	113	113	109	48	22	113	183
11. MOH & EMOH	45	42	45	43	45	43	45	45	43	19	9	45	73
12. OPER BTU (GBTU)	454.297	413.226	601.257	692.178	681.215	647.169	688.811	694.951	646.652	302.779	103.373	541.631	947.783
13. NET GEN (MWH)	36875	33440	50327	60180	66333	55879	59126	59632	55837	26242	9041	44963	80246
14. ANOHR (BTU/KWH)	12320	12357	11947	11502	10270	11582	11650	11654	11581	11538	11434	12046	11811
15. NOF (%)	43.1	42.2	56.8	87.8	91.5	87.9	88.6	88.4	88.1	90.7	88.6	50.8	64.6
16. NPC (MW)	189	189	189	179	179	179	179	179	179	189	189	189	184

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 9 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 5	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	79.8	79.9	28.4	77.2	79.8	79.9	79.8	79.8	79.9	79.7	79.9	79.8	75.3
2. POF	0.0	0.0	64.5	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
3. EUOF	20.2	20.1	7.1	19.5	20.2	20.1	20.2	20.2	20.1	20.3	20.1	20.2	19.0
4. EUOR	20.2	20.1	20.1	20.1	20.2	20.1	20.2	20.2	20.1	20.3	20.1	20.2	20.2
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	666	623	236	624	666	645	666	666	645	666	645	666	7414
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	78	73	508	95	78	75	78	78	75	79	75	78	1370
9. POH	0	0	480	24	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	126	118	45	118	126	122	126	126	122	127	122	126	1404
11. MOH & EMOH	24	22	8	22	24	23	24	24	23	24	23	24	265
12. OPER BTU (GBTU)	796.599	717.819	339.438	1145.187	1189.238	1210.604	1282.557	1295.477	1221.876	1190.575	1066.387	925.913	12381.670
13. NET GEN (MWH)	75304	67630	32285	109917	113300	114241	119704	121038	115341	112647	102367	88508	1172282
14. ANOHR (BTU/KWH)	10578	10614	10514	10419	10496	10597	10714	10703	10594	10569	10417	10461	10562
15. NOF (%)	46.7	44.9	56.5	75.9	73.3	76.3	77.5	78.3	77.1	69.9	65.6	54.9	66.7
16. NPC (MW)	242	242	242	232	232	232	232	232	232	242	242	242	237

17. ANOHR EQUATION ANOHR = NOF(-12.3085) + 11383

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 10 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 6	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	76.6	61.3	39.5	72.2
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	48.4	5.7
3. EUOF	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	18.7	12.1	22.1
4. EUOR	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	619	579	619	599	619	599	619	619	599	619	479	319	6888
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	125	117	125	120	125	121	125	125	121	126	241	425	1896
9. POH	0	0	0	0	0	0	0	0	0	0	144	360	504
10. FOH & EFOH	138	129	138	133	138	133	138	138	133	138	107	71	1532
11. MOH & EMOH	37	34	37	35	37	35	37	37	35	37	28	19	406
12. OPER BTU (GBTU)	1265.540	1145.843	1494.213	1762.542	1789.503	1805.333	1936.202	1959.355	1837.494	1790.074	1292.431	754.665	18833.195
13. NET GEN (MWH)	119596	107904	142302	169859	171130	171710	183145	185538	174850	170071	124139	72168	1792412
14. ANOHR (BTU/KWH)	10582	10619	10500	10377	10457	10514	10572	10560	10509	10525	10411	10457	10507
15. NOF (%)	49.3	47.5	58.6	76.2	74.3	77.1	79.5	80.6	78.5	70.1	66.1	57.7	68.1
16. NPC (MW)	392	392	392	372	372	372	372	372	372	392	392	392	382

17. ANOHR EQUATION ANOHR = NOF(-4.1530) + 10790

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	0.1	16.0	96.0	81.3
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	99.9	83.3	0.0	15.3
3. EUOF	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	0.0	0.7	4.0	3.4
4. EUOR	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	0.0	4.2	4.0	4.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	10	11	38	315	326	316	326	327	80	0	4	7	1760
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	734	685	706	404	418	404	418	417	640	745	716	737	7024
9. POH	0	0	0	0	0	0	0	0	0	744	600	0	1344
10. FOH & EFOH	14	13	14	14	14	14	14	14	14	0	2	14	141
11. MOH & EMOH	16	15	16	15	16	15	16	16	15	0	3	16	159
12. OPER BTU (GBTU)	5.178	5.361	19.325	89.819	70.187	84.203	95.450	88.790	37.596	0.000	1.857	3.527	501.293
13. NET GEN (MWH)	319	331	1180	5003	3637	4644	5305	4826	2353	0	113	217	27928
14. ANOHR (BTU/KWH)	16232	16196	16377	17953	19298	18132	17992	18398	15978	0	16434	16253	17949
15. NOF (%)	99.7	94.0	97.0	52.9	37.2	49.0	54.2	49.2	98.0	0.0	88.3	96.9	51.2
16. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 12 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	93.0	93.1	93.0	93.0	93.0	93.1	93.0	93.0	93.1	93.0	77.5	24.1	85.9
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7	74.2	7.7
3. EUOF	7.0	6.9	7.0	7.0	7.0	6.9	7.0	7.0	6.9	7.0	5.8	1.7	6.4
4. EUOR	7.0	6.9	7.0	7.0	7.0	6.9	7.0	7.0	6.9	7.0	7.0	6.8	7.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	10	10	39	306	316	306	317	317	75	36	19	2	1753
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	734	686	705	413	428	414	427	427	645	709	701	742	7031
9. POH	0	0	0	0	0	0	0	0	0	0	120	552	672
10. FOH & EFOH	36	33	36	35	36	35	36	36	35	36	29	9	392
11. MOH & EMOH	16	15	16	15	16	15	16	16	15	16	13	4	173
12. OPER BTU (GBTU)	4.861	4.994	19.585	80.632	59.990	73.623	83.042	76.764	35.271	18.381	9.824	0.927	467.894
13. NET GEN (MWH)	300	308	1198	4798	3475	4346	4897	4485	2198	1117	601	57	27780
14. ANOHR (BTU/KWH)	16203	16214	16348	16805	17263	16940	16958	17116	16047	16456	16346	16263	16843
15. NOF (%)	93.8	96.3	96.0	52.3	36.7	47.3	51.5	47.2	97.7	97.0	98.8	89.1	51.1
16. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 13 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	93.0	45.0	54.0	93.0	93.0	93.1	93.0	93.0	93.1	93.0	93.1	93.0	85.9
2. POF	0.0	51.7	41.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
3. EUOF	7.0	3.3	4.0	7.0	7.0	6.9	7.0	7.0	6.9	7.0	6.9	7.0	6.4
4. EUOR	7.0	6.8	6.9	7.0	7.0	6.9	7.0	7.0	6.9	7.0	6.9	7.0	7.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	10	5	23	306	316	306	317	317	81	37	25	7	1750
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	734	691	721	413	428	414	427	427	639	708	695	737	7034
9. POH	0	360	312	0	0	0	0	0	0	0	0	0	672
10. FOH & EFOH	36	16	21	35	36	35	36	36	35	36	35	36	393
11. MOH & EMOH	16	7	9	15	16	15	16	16	15	16	15	16	172
12. OPER BTU (GBTU)	5.088	2.470	11.826	88.262	69.746	83.257	92.462	86.094	37.614	18.857	12.251	3.491	511.418
13. NET GEN (MWH)	319	155	738	4953	3590	4579	5060	4609	2368	1164	7640	219	35394
14. ANOHR (BTU/KWH)	15950	15935	16024	17820	19428	18182	18273	18680	15884	16200	1604	15941	14449
15. NOF (%)	99.7	96.9	100.3	54.0	37.9	49.9	53.2	48.5	97.4	98.3	955.0	97.8	65.2
16. NPC (MW)	32	32	32	30	30	30	30	30	30	32	32	32	31

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 14 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 4	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	93.0	93.1	39.0	62.0	93.0	93.1	93.0	93.0	93.1	93.0	93.1	93.0	85.9
2. POF	0.0	0.0	58.1	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
3. EUOF	7.0	6.9	3.0	4.6	7.0	6.9	7.0	7.0	6.9	7.0	6.9	7.0	6.4
4. EUOR	7.0	6.9	7.1	6.9	7.0	6.9	7.0	7.0	6.9	7.0	6.9	7.0	7.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	11	12	15	220	316	306	317	317	73	39	26	8	1660
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	733	684	729	499	428	414	427	427	647	706	694	736	7124
9. POH	0	0	432	240	0	0	0	0	0	0	0	0	672
10. FOH & EFOH	36	33	15	23	36	35	36	36	35	36	35	36	392
11. MOH & EMOH	16	15	7	10	16	15	16	16	15	16	15	16	173
12. OPER BTU (GBTU)	6.916	7.451	9.514	83.791	94.554	110.465	122.818	115.271	44.272	25.111	16.222	5.013	641.398
13. NET GEN (MWH)	440	474	600	4902	5207	6270	6957	6441	2740	1557	1023	319	36930
14. ANOHR (BTU/KWH)	15718	15719	15857	17093	18159	17618	17654	17896	16158	16128	15857	15715	17368
15. NOF (%)	97.6	96.3	97.6	57.1	42.3	52.5	56.3	52.1	96.2	97.4	96.0	97.3	55.6
16. NPC (MW)	41	41	41	39	39	39	39	39	39	41	41	41	40

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
HOOKERS PT 5	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	83.9	83.9	83.9	28.0	62.2	83.9	83.9	83.9	83.9	83.9	83.9	83.9	77.5
2. POF	0.0	0.0	0.0	66.8	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
3. EUOF	16.1	16.1	16.1	5.3	12.0	16.1	16.1	16.1	16.1	16.1	16.1	16.1	14.9
4. EUOR	16.1	16.1	16.1	15.9	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	10	11	41	98	213	283	293	293	65	39	25	7	1378
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	734	685	703	621	531	437	451	451	655	706	695	737	7406
9. POH	0	0	0	480	192	0	0	0	0	0	0	0	672
10. FOH & EFOH	89	83	89	28	66	86	89	89	86	89	86	89	969
11. MOH & EMOH	31	29	31	10	23	30	31	31	30	31	30	31	338
12. OPER BTU (GBTU)	10.095	10.610	41.106	65.497	116.990	188.856	207.875	195.215	66.231	40.054	25.631	7.081	975.241
13. NET GEN (MWH)	639	670	2589	3632	5910	10220	11375	10428	4091	2486	1616	448	54104
14. ANOHR (BTU/KWH)	15798	15836	15877	18033	19795	18479	18275	18720	16189	16112	15861	15806	18025
15. NOF (%)	95.4	90.9	94.2	55.3	41.4	53.9	57.9	53.1	93.9	95.1	96.5	95.5	58.6
16. NPC (MW)	67	67	67	67	67	67	67	67	67	67	67	67	67

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 16 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON CT 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	64.9	65.1	64.9	65.0	64.9	65.0	64.9	64.9	65.0	65.0	36.8	62.9	62.5
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.3	3.2	3.8
3. EUOF	35.1	34.9	35.1	35.0	35.1	35.0	35.1	35.1	35.0	35.0	19.9	33.9	33.7
4. EUOR	35.1	34.9	35.1	35.0	35.1	35.0	35.1	35.1	35.0	35.0	35.0	35.0	35.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	4	3	8	28	4	12	22	14	7	6	1	3	112
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	740	693	736	691	740	708	722	730	713	739	719	741	8672
9. POH	0	0	0	0	0	0	0	0	0	0	312	24	336
10. FOH & EFOH	149	139	149	144	149	144	149	149	144	149	82	144	1691
11. MOH & EMOH	112	104	112	108	112	108	112	112	108	112	61	108	1269
12. OPER BTU (GBTU)	0.967	0.904	2.024	7.393	0.985	3.118	5.758	3.584	1.852	1.551	0.392	0.920	29.448
13. NET GEN (MWH)	60	57	126	458	61	193	356	221	115	96	24	58	1825
14. ANOHR (BTU/KWH)	16117	15860	16063	16142	16148	16155	16174	16217	16104	16156	16333	15862	16136
15. NOF (%)	88.2	111.8	92.6	136.3	127.1	134.0	134.8	131.5	136.9	94.1	141.2	113.7	112.4
16. NPC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 17 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND CT 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	64.9	65.1	64.9	65.0	64.9	65.0	64.9	64.9	65.0	35.7	65.0	64.9	62.5
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.1	0.0	0.0	3.8
3. EUOF	35.1	34.9	35.1	35.0	35.1	35.0	35.1	35.1	35.0	19.2	35.0	35.1	33.7
4. EUOR	35.1	34.9	35.1	35.0	35.1	35.0	35.1	35.1	35.0	35.0	35.0	35.1	35.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	4	3	8	28	4	12	22	14	7	3	3	4	112
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	740	693	736	691	740	708	722	730	713	742	717	740	8672
9. POH	0	0	0	0	0	0	0	0	0	336	0	0	336
10. FOH & EFOH	149	139	149	144	149	144	149	149	144	82	144	149	1691
11. MOH & EMOH	112	104	112	108	112	108	112	112	108	61	108	112	1269
12. OPER BTU (GBTU)	0.967	0.903	2.045	7.432	0.981	3.185	5.873	3.666	1.840	0.849	0.665	0.961	29.367
13. NET GEN (MWH)	61	57	128	460	61	197	363	226	114	53	41	60	1821
14. ANOHR (BTU/KWH)	15852	15842	15977	16157	16082	16168	16179	16221	16140	16019	16220	16017	16127
15. NOF (%)	89.7	111.8	94.1	136.9	127.1	136.8	137.5	134.5	135.7	103.9	80.4	88.2	112.1
16. NPC (MW)	17	17	17	12	12	12	12	12	12	17	17	17	15

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND CT 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	69.1	33.3	0.0	0.0	51.1	68.9	69.1	69.1	68.9	69.1	68.9	69.1	53.2
2. POF	0.0	51.7	100.0	100.0	25.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.9
3. EUOF	30.9	14.9	0.0	0.0	23.1	31.1	30.9	30.9	31.1	30.9	31.1	30.9	23.9
4. EUOR	30.9	31.0	0.0	0.0	31.2	31.1	30.9	30.9	31.1	30.9	31.1	30.9	31.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	4	2	0	0	3	15	27	17	8	7	3	4	90
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	740	694	744	719	741	705	717	727	712	738	717	740	8694
9. POH	0	360	744	719	192	0	0	0	0	0	0	0	2015
10. FOH & EFOH	115	52	0	0	86	112	115	115	112	115	112	115	1049
11. MOH & EMOH	115	52	0	0	86	112	115	115	112	115	112	115	1049
12. OPER BTU (GBTU)	4.816	2.120	0.000	0.000	3.632	17.246	31.564	19.884	9.241	7.941	3.291	4.784	104.519
13. NET GEN (MWH)	302	133	0	0	226	1064	1950	1228	577	494	205	300	6479
14. ANOHR (BTU/KWH)	15947	15940	0	0	16071	16209	16187	16192	16016	16075	16054	15947	16132
15. NOF (%)	94.4	83.1	0.0	0.0	121.5	114.4	116.5	116.5	116.3	88.2	85.4	93.8	101.4
16. NPC (MW)	80	80	80	62	62	62	62	62	62	80	80	80	71

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND CT 3	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	69.1	35.6	69.1	69.1	69.1	68.9	69.1	69.1	68.9	69.1	68.9	69.1	66.4
2. POF	0.0	48.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3. EUOF	30.9	16.1	30.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	29.8
4. EUOR	30.9	31.1	30.9	30.9	30.9	31.1	30.9	30.9	31.1	30.9	31.1	30.9	31.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	4	2	9	32	4	17	30	19	8	7	3	4	139
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	740	694	735	687	740	703	714	725	712	738	717	740	8645
9. POH	0	336	0	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	115	56	115	111	115	112	115	115	112	115	112	115	1308
11. MOH & EMOH	115	56	115	111	115	112	115	115	112	115	112	115	1308
12. OPER BTU (GBTU)	4.832	2.341	10.537	38.158	5.098	19.715	35.610	22.464	9.311	8.285	3.301	4.780	164.432
13. NET GEN (MWH)	304	147	659	2380	318	1221	2208	1394	583	517	207	301	10239
14. ANOHR (BTU/KWH)	15895	15925	15989	16033	16031	16147	16128	16115	15971	16025	15947	15880	16059
15. NOF (%)	95.0	91.9	91.5	120.0	128.2	115.8	118.7	118.3	117.5	92.3	86.3	94.1	103.7
16. NPC (MW)	80	80	80	62	62	62	62	62	62	80	80	80	71

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 20 OF 23

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
PHILLIPS 1	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	0.0	0.0	0.0	0.0	0.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	49.1
2. POF	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5
3. EUOF	0.0	0.0	0.0	0.0	0.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	9.3
4. EUOR	0.0	0.0	0.0	0.0	0.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	0	0	0	0	0	174	197	168	183	193	63	21	999
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	744	696	744	719	744	546	547	576	537	552	657	723	7785
9. POH	744	696	744	719	744	0	0	0	0	0	0	0	3647
10. FOH & EFOH	0	0	0	0	0	65	67	67	65	67	65	67	463
11. MOH & EMOH	0	0	0	0	0	50	52	52	50	52	50	52	358
12. OPER BTU (GBTU)	0.000	0.000	0.000	0.000	0.000	26.569	30.790	26.059	28.510	28.640	9.814	3.297	153.679
13. NET GEN (MWH)	0	0	0	0	0	2846	3297	2791	3053	3069	1051	353	16460
14. ANOHR (BTU/KWH)	0	0	0	0	0	9336	9339	9337	9338	9332	9338	9340	9337
15. NOF (%)	0.0	0.0	0.0	0.0	0.0	96.2	98.4	97.7	98.1	93.5	98.1	98.9	96.9
16. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
PHILLIPS 2	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	0.0	0.0	0.0	0.0	0.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	49.1
2. POF	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5
3. EUOF	0.0	0.0	0.0	0.0	0.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	9.3
4. EUOR	0.0	0.0	0.0	0.0	0.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	0	0	0	0	0	172	195	167	161	191	62	21	989
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	744	696	744	719	744	548	549	577	539	554	658	723	7795
9. POH	744	696	744	719	744	0	0	0	0	0	0	0	3647
10. FOH & EFOH	0	0	0	0	0	65	67	67	65	67	65	67	463
11. MOH & EMOH	0	0	0	0	0	50	52	52	50	52	50	52	358
12. OPER BTU (GBTU)	0.000	0.000	0.000	0.000	0.000	26.233	30.473	25.788	28.211	28.314	9.730	3.241	151.990
13. NET GEN (MWH)	0	0	0	0	0	2810	3263	2762	3021	3034	1042	347	16279
14. ANOHR (BTU/KWH)	0	0	0	0	0	9336	9339	9337	9338	9332	9338	9340	9337
15. NOF (%)	0.0	0.0	0.0	0.0	0.0	96.1	98.4	97.3	98.2	93.4	98.9	97.2	96.8
16. NPC (MW)	17	17	17	17	17	17	17	17	17	17	17	17	17

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2000 - DECEMBER 2000

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK	JAN 00	FEB 00	MAR 00	APR 00	MAY 00	JUN 00	JUL 00	AUG 00	SEP 00	OCT 00	NOV 00	DEC 00	2000
1. EAF (%)	88.6	88.5	88.6	88.6	48.7	88.6	88.6	88.6	88.6	88.6	67.9	88.6	83.5
2. POF	0.0	0.0	0.0	0.0	45.2	0.0	0.0	0.0	0.0	0.0	23.3	0.0	5.7
3. EUOF	11.4	11.5	11.4	11.4	6.2	11.4	11.4	11.4	11.4	11.4	8.8	11.4	10.8
4. EUOR	11.4	11.5	11.4	11.4	11.3	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
5. PH	744	696	744	719	744	720	744	744	720	745	720	744	8784
6. SH	613	573	613	593	336	593	613	613	593	613	455	613	6821
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	131	123	131	126	408	127	131	131	127	132	265	131	1963
9. POH	0	0	0	0	336	0	0	0	0	0	168	0	504
10. FOH & EFOH	20	19	20	19	11	19	20	20	19	20	15	20	222
11. MOH & EMOH	65	61	65	63	35	63	65	65	63	65	48	65	723
12. OPER BTU (GBTU)	1499.640	1400.060	1521.020	1497.220	849.667	1510.070	1563.370	1565.400	1506.210	1542.830	1097.640	1511.970	17065.097
13. NET GEN (MWH)	141157	131890	143330	141408	80119	142713	147633	147840	142321	145546	103320	142288	1609565
14. ANOHR (BTU/KWH)	10624	10615	10612	10588	10605	10581	10590	10588	10583	10600	10624	10626	10602
15. NOF (%)	92.1	92.1	93.5	95.4	95.4	96.3	96.3	96.5	96.0	95.0	90.8	92.8	94.4
16. NPC (MW)	250	250	250	250	250	250	250	250	250	250	250	250	250

FILED:
SUSPENDED:
EFFECTIVE: 10/01/99
DOCKET NO. : 000001-EI
ORDER NO.:

ORGINAL SHEET NO. 8.401.00E
PAGE 23 OF 23

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)

TAMPA ELECTRIC COMPANY

EXHIBIT OF MARK J. HORNICK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 17
COMPANY/ WITNESS: Hornick
DATE 11-22-99

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)

INDEX

Document No.	Title	Page
1	Transportation Benchmark Calculation	1
2	Coal Benchmark Calculation	3

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)
DOCUMENT NO. 1
PAGE 1 OF 2

1998 TRANSPORTATION BENCHMARK CALCULATION

Average Rail Mileage to Tampa		1242	Miles	(Note 1)
x	Average of Lowest Two Publicly Available Florida Rail Rates	2.125 26.39	¢/ton mile	(Note 2)
+	Costs of Privately Owned Rail Cars	1.75		(Note 3)
Transportation Benchmark for The Year Ended 12/31/98		28.14		(Note 4)

Notes

1/ Weighted average domestic rail miles from all Tampa Electric waterborne coal supplies to plants. Rail miles for imported coal sources are measured from port of entry.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates including discounts for volume and private rail cars. The current publicly available rail rates to Florida utilities on a cents per ton-mile basis for 1998 are as follows:

JEA	¢	2.29
Orlando	¢*	1.99
Lakeland	¢*	2.26
Gainesville	¢	2.61
* Average of Lowest Two	¢	2.125

3/ The cost of Private rail cars was approved in the original stipulation as $2.00 per ton. Subsequent negotiation between Tampa Electric and Public Service Commission Staff resulted in an agreed upon estimated cost of $1.75 per ton.

4/ Calculated by multiplying average domestic rail mileage to Tampa by Florida rail coal market costs (cents per ton-mile), then adding the costs of privately-owned rail cars.

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)
DOCUMENT NO. 1
PAGE 2 OF 2

1998 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources [redacted] divided by 6,391,305.11)	[redacted]
Transportation Benchmark	$28.14
Over/(Under) Benchmark	[redacted]
Total Tons Transported in 1998	7,315,351.25
Total Transportation Cost in 1998	[redacted]
Total Amount Allowable for Recovery Using Benchmark ($28.14 x 7,315,351.25)	$205,872,272.55
Total Cost Over/(Under) Benchmark – 1998	[redacted]
Prior Years' Cumulative Benefit (1988 – 1997)	[redacted]
Net Benefit for 1988 – 1998	[redacted]

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)
DOCUMENT NO. 2
PAGE 1 OF 2

MARKET BASED COAL CALCULATION – 1998

Base Price of Coal As of 12/31/92	$38.00
CPI-U Index Value at 12/31/92	141.9
CPI-U Index Value at 12/31/98	163.9
Percent Change in CPI-U From 12/31/92 To 12/31/98	15.5%
1998 Gatliff Coal Price Benchmark (38.00 x (1 + 0.155))	$43.89

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MJH – 1)
DOCUMENT NO. 2
PAGE 2 OF 2

COAL MARKET PRICE APPLICATION – 1998

Tampa Electric Weighted Average per Ton Price of Coal Purchased	[redacted]
Coal Price Benchmark	$43.89
Over/(Under) Benchmark	[redacted]
Total Tons Purchased in 1998	757,930
Total Cost in 1998	[redacted]
Total Amount Allowable for Recovery Using Benchmark (43.89 x 757,930)	$33,265,547.70
Total Cost Over/(Under) Benchmark – 1998	[redacted]

	Once Burned Fuel	Twice Burned Fuel	Total	Last Month of operation	Months to end of operations	Monthly Amortization
St. Lucie Unit 1 - Fall 1999						
Cycle ID	**15**	**14**				
Allocated Acquisition Cost	25,529,835.77	39,171,924.93				
Allocated Capitalized Cost	442,399.56	1,951,318.06				
Portion to Recover as Once Burned	0.352					
Portion to Recover as Twice Burned	0.160	0.241				
Once Burned Fuel	9,142,226.84		9,142,226.84			
Twice Burned Fuel	4,675,002.36	9,910,701.56	14,585,703.92			
			23,727,930.76	3/2016	195	$121,681.70
St. Lucie Unit 2 - Spring 2000						
Cycle ID	**11**	**10**				
Allocated Acquisition Cost	22,302,221.95	23,281,764.68				
Allocated Capitalized Cost	456,836.79	838,846.98				
Portion to Recover as Once Burned	0.340					
Portion to Recover as Twice Burned	0.250	0.240				
Once Burned Fuel	7,738,079.97		7,738,079.97			
Twice Burned Fuel	5,689,764.69	5,788,946.80	11,478,711.48			
			19,216,791.46	4/2023	280	68,631.40
Turkey Point Unit 3 - Spring 2000						
Cycle ID	**17**	**16**				
Allocated Acquisition Cost	21,484,680.78	27,882,597.75				
Allocated Capitalized Cost	690,519.48	1,171,836.90				
Portion to Recover as Once Burned	0.430					
Portion to Recover as Twice Burned	0.130	0.142				
Once Burned Fuel	9,535,336.11		9,535,336.11			
Twice Burned Fuel	2,882,776.03	4,125,729.72	7,008,505.75			
			16,543,841.87	7/2012	151	109,561.87
Turkey Point Unit 4 - Fall 2000						
Cycle ID	**18**	**17**				
Allocated Acquisition Cost	23,922,819.48	24,615,125.04				
Allocated Capitalized Cost	180,457.54	762,919.85				
Portion to Recover as Once Burned	0.370					
Portion to Recover as Twice Burned	0.200	0.130				
Once Burned Fuel	8,918,212.50		8,918,212.50			
Twice Burned Fuel	4,820,655.40	3,299,145.84	8,119,801.24			
			17,038,013.74	4/2013	160	106,487.59
	$53,402,053.90	$23,124,523.91	$76,526,577.81			$406,362.55

Year	Amortization
2,000	$4,876,350.56
2,001	4,876,350.56
2,002	4,876,350.56
2,003	4,876,350.56
2,004	4,876,350.56
2,005	4,876,350.56
2,006	4,876,350.56
2,007	4,876,350.56
2,008	4,876,350.56
2,009	4,876,350.56
2,010	4,876,350.56
2,011	4,876,350.56
2,012	4,328,541.23
2,013	2,709,707.47
2,014	2,283,757.13
2,015	2,283,757.13
2,016	1,188,621.87
2,017	823,576.78
2,018	823,576.78
2,019	823,576.78
2,020	823,576.78
2,021	823,576.78
2,022	823,576.78
2,023	274,525.59
	$76,526,577.81

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 18
COMPANY/ WITNESS: Wade
DATE: 11-23-99

APPENDIX I

FUEL COST RECOVERY

TRUE-UP CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 19
COMPANY/ WITNESS: Dubin
DATE: 11-22-00

KMD - 1
DOCKET NO. 990001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-4
APRIL 1, 1999

APPENDIX I

FUEL COST RECOVERY CLAUSE

TABLE OF CONTENTS

PAGE	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4	CALCULATION OF FINAL TRUE-UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998

1	End of Period True-up for the nine month period April through December 1998 (from page 4, lines D7 & D8)	$	(95,639,291)
2	Less - Estimated/Actual True-up for the same period *		(129,170,389)
3	Net True-up for the nine month period April through December 1998	$	33,531,098

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-98-1715-FOF-EI dated December 18, 1998

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998

	LINE NO.			(1) ACTUAL	(2) UPDATED ESTIMATE (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	1	a	Fuel Cost of System Net Generation	$ 1,072,553,806	$ 1,030,560,149	$ 41,993,657	4.1 %
		b	Nuclear Fuel Disposal Costs	17,094,185	16,845,686	248,499	1.5 %
		c	Coal Cars Depreciation & Return	3,749,863	3,723,771	26,092	0.7 %
		d	Nuclear Thermal Uprate Amortization & Return	3,241,844	3,241,844	0	0.0 %
		e	Gas Pipelines Depreciation & Return	2,393,429	2,393,429	(0)	0.0 %
		f	DOE Decontamination & Decommissioning Fund Payment	5,435,701	5,586,000	(150,299)	(2.7) %
	2		Fuel Cost of Power Sold	(47,417,729)	(47,669,328)	251,599	(0.5) %
	3	a	Fuel Cost of Purchased Power	108,131,655	110,451,646	(2,319,991)	(2.1) %
		b	Energy Payments to Qualifying Facilities	85,487,693	98,156,848	(12,669,155)	(12.9) %
	4		Energy Cost of Economy Purchases	22,836,002	46,454,218	(23,618,216)	(50.8) %
	5		Total Fuel Costs & Net Power Transactions	$ 1,273,506,448	$ 1,269,744,262	$ 3,762,186	0.3 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (16,335,854)	$ (16,794,945)	$ 459,090	(2.7) %
		b	Reactive and Voltage Control Fuel Revenues	(432,301)	(232,451)	(199,850)	86.0 %
		c	Inventory Adjustments	180,394	190,120	(9,726)	N/A
		d	Non Recoverable Oil/Tank Bottoms	(8,018)	211,198	(219,216)	(103.8) %
		e	Modifications to Burn Low Gravity Oil	1,975,051	1,375,634	599,417	43.6 %
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 1,258,885,721	$ 1,254,493,818	$ 4,391,903	0.4 %
C	1		Jurisdictional kWh Sales	67,127,103,384	65,204,627,493	1,922,475,891	2.9 %
	2		Sale for Resale	350,577,713	343,106,944	7,470,769	2.2 %
	3		Total Sales (Excluding RTP Incremental)	67,477,681,097	65,547,734,437	1,929,946,660	2.9 %
	4			N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 1,301,516,289	$ 1,263,943,770	$ 37,572,519	3.0 %
		a	Prior Period True-up Provision	(135,509,164)	(135,509,164)	0	0.0 %
		b	GPIF, Net of Revenue Taxes (b)	(2,855,039)	(2,855,039)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes	(126)	(150)	24	(16.1) %
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 1,163,151,960	$ 1,125,579,418	$ 37,572,543	3.3 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 1,258,885,721	$ 1,254,493,818	$ 4,391,903	0.4 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	830,083	542,109	287,973	53.1 %
		d	*D&D Fund Payments -100% Retail*	5,435,701	0	5,435,701	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	1,252,619,936	1,253,951,709	4,103,929	0.3 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 1,253,287,887	$ 1,248,885,777	$ 4,402,110	0.4 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (90,135,927)	$ (123,306,360)	$ 33,170,433	(26.9) %
	8		Interest Provision for the Month	(5,503,364)	(5,864,029)	360,665	(6.2) %
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(135,509,164)	(135,509,164)	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	13,491,202	13,491,202	0	0.0 %
	10		Prior Period True-up Collected/(Refunded) This Period	135,509,164	135,509,164	(0)	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (82,148,089)	$ (115,679,187)	$ 33,531,098	(29.0) %

NOTES
(a) Per Schedule E-1b, filed October 5, 1998.
(b) Generation Performance Incentive Factor is (($5,801,940 / 2) / 9) x 98.4167%) - See Order Nos. PSC-97-1045-FOF-EI & PSC-98-0412-FOF-EI.

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO 990001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-6
APRIL 1, 1999

APPENDIX II
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4	CALCULATION OF FINAL TRUE-UP AMOUNT
5	CALCULATION OF INTEREST PROVISION
6	CALCULATION OF FINAL TRUE-UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP AMOUNT FOR THE
NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998

1.	True-up Amount for the nine month period ended December 31, 1998	$ 70,611,128
2.	Less: Estimated/Actual Over/(Under) Recovery for the same nine month period (a)	65,406,291
3.	Net True-up: Over/(Under) Recovery to be carried forward to the January through December 2000 period	$5,204,837

Notes: (a) Approved in FPSC Order No. PSC-98-1715-FOF-EI dated December 18, 1998.

( ) Denotes an underrecovery

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH DECEMBER 1998

LINE NO.		(1) APR 1998	(2) MAY 1998	(3) JUN 1998	(4) JUL 1998	(5) AUG 1998	(6) SEP 1998	(7) OCT 1998	(8) NOV 1998	(9) DEC 1998	(10) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 11,740,754	$ 9,944,103	$ 9,940,061	$ 1,171,874	$ 8,342,282	$ 10,014,980	$ 9,737,851	$ 9,740,305	$ 9,786,006	$ 80,418,216	1.
2.	JEA/UPS Capacity Charges	-	-	-	-	-	-	-	-	-	-	2.
3.	QF Capacity Charges	24,953,830	24,885,138	24,931,411	25,161,758	24,977,643	24,936,518	24,934,246	24,915,329	24,906,527	224,602,401	3.
4.	SJRPP Capacity Charges	7,332,267	7,317,575	6,809,525	7,111,523	6,956,174	7,418,693	6,818,859	6,601,346	6,137,867	62,503,830	4.
4a.	SJRPP Suspension Accrual	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	3,525,000	4a.
4b.	Return Requirements on SJRPP Suspension Liability	(26,271)	(30,312)	(34,354)	(38,396)	(42,437)	(46,479)	(50,521)	(54,562)	(58,604)	(381,936)	4b.
5.	SJRPP Deferred Interest Payment	56,435	56,435	56,435	56,435	388,028	388,028	(62,888)	(62,888)	(62,888)	813,133	5.
6.	Cypress Settlement (Capacity)	1,530,589	-	-	-	-	-	1,530,589	-	148,450	3,209,628	6.
7.	Transmission of Electricity by Others - FPL Sales	143,986	447,468	30,446	238,364	61,745	201,610	16,200	2,438	60,909	1,203,165	7.
8.	Revenues from Capacity Sales	(735,948)	(11,618,781)	(23,692,850)	(16,581,063)	(6,992,235)	(5,371,137)	(738,145)	(398,284)	(1,281,622)	(67,410,065)	8.
9.	Total (Lines 1 through 8)	$ 45,387,310	$ 31,393,293	$ 18,432,341	$ 17,512,162	$ 34,082,866	$ 37,933,881	$ 42,577,858	$ 41,135,350	$ 40,028,312	$ 308,483,372	9.
10.	Jurisdictional Separation Factor (a)	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	N/A	10.
11.	Jurisdictional Capacity Charges	44,116,107	30,514,033	17,916,090	17,021,683	33,128,277	36,871,432	41,385,342	39,983,235	38,907,203	299,843,401	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(42,709,194)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 39,370,641	$ 25,768,567	$ 13,170,624	$ 12,276,217	$ 28,382,811	$ 32,125,966	$ 36,639,876	$ 35,237,769	$ 34,161,737	$ 257,134,207	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 25,835,592	$ 26,090,144	$ 32,242,608	$ 34,852,559	$ 33,664,909	$ 33,739,517	$ 32,198,129	$ 28,503,261	$ 26,726,799	$ 273,853,518	14.
15.	Prior Period True-up Provision	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	50,684,184	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 31,467,168	$ 31,721,720	$ 37,874,184	$ 40,484,135	$ 39,296,485	$ 39,371,093	$ 37,829,705	$ 34,134,837	$ 32,358,375	$ 324,537,702	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(7,903,472)	5,953,153	24,703,560	28,207,918	10,913,675	7,245,126	1,189,829	(1,102,932)	(1,803,362)	67,403,495	17.
18.	Interest Provision for Month	255,933	226,746	274,082	373,670	437,023	440,997	419,567	408,123	371,491	3,207,632	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	50,684,185	37,405,071	37,953,394	57,299,460	80,249,472	85,968,593	88,023,141	84,000,961	77,674,576	50,684,185	19.
20.	Deferred True-up - Over/(Under) Recovery	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(50,684,184)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 49,176,566	$ 49,724,889	$ 69,070,955	$ 92,020,967	$ 97,740,089	$ 99,794,637	$ 95,772,457	$ 89,446,072	$ 82,382,625	$ 82,382,625	22.

Notes:
(a) Per K. M. Dubin's Testimony Appendix IV, Page 3, Docket No. 980001-EI, filed January 12, 1998
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD APRIL THROUGH DECEMBER 1998

LINE NO.		(1) APR 1998	(2) MAY 1998	(3) JUN 1998	(4) JUL 1998	(5) AUG 1998	(6) SEP 1998	(7) OCT 1998	(8) NOV 1998	(9) DEC 1998	(10) TOTAL	LINE NO.
1.	Beginning True-up Amount	$62,455,681	$49,176,566	$49,724,889	$69,070,955	$92,020,967	$97,740,089	$99,794,637	$95,772,457	$89,446,072	n/a	1.
2.	Ending True-up Amount Before Interest	48,920,633	49,498,143	68,796,874	91,647,297	97,303,066	99,353,639	95,352,890	89,037,949	82,011,134	n/a	2.
3.	Total Beginning & Ending True-up Amount (Lines 1+2)	111,376,314	98,674,709	118,521,763	160,718,253	189,324,033	197,093,728	195,147,526	184,810,406	171,457,206	n/a	3.
4.	Average True-up Amount (50 % of Line 3)	$55,688,157	$49,337,355	$59,260,882	$80,359,126	$94,662,017	$98,546,864	$97,573,763	$92,405,203	$85,728,603	n/a	4.
5.	Interest Rate - First day of Reporting Business Month	5.50000%	5.53000%	5.50000%	5.60000%	5.56000%	5.52000%	5.22000%	5.10000%	5.50000%	n/a	5.
6.	Interest Rate - First day of Subsequent Business Month	5.53000%	5.50000%	5.60000%	5.56000%	5.52000%	5.22000%	5.10000%	5.50000%	4.90000%	n/a	6.
7.	Total Interest Rate (Lines 5+6)	11.03000%	11.03000%	11.10000%	11.16000%	11.08000%	10.74000%	10.32000%	10.60000%	10.40000%	n/a	7.
8.	Average Interest Rate (50 % of Line 7)	5.51500%	5.51500%	5.55000%	5.58000%	5.54000%	5.37000%	5.16000%	5.30000%	5.20000%	n/a	8.
9.	Monthly Average Interest Rate (1/12 of Line 8)	0.45958%	0.45958%	0.46250%	0.46500%	0.46167%	0.44750%	0.43000%	0.44167%	0.43333%	n/a	9.
10.	Interest Provision for the Month (Line 4 X Line 9)	$255,933	$226,746	$274,082	$373,670	$437,023	$440,997	$419,567	$408,123	$371,491	$2,008,451	10.

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE NINE MONTH PERIOD APRIL 1998 THROUGH DECEMBER 1998

		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE	(4) PERCENTAGE CHANGE
1.	Payments to Non-cogenerators	$ 143,735,179	$ 159,114,020	$ (15,378,841)	-9.7%
2	Payments to Cogenerators	224,602,401	229,349,168	(4,746,767)	-2.1%
3.	SJRPP Suspension Accrual	3,525,000	3,525,003	(3)	N/A
4.	Return Requirements on SJRPP Suspension Liability	(381,936)	(381,936)	0	N/A
4b.	Cypress Settlement (Capacity)	3,209,628	1,530,589	1,679,039	109.7%
5.	Transmission of Electricity by Others - FPL Sales	1,203,165	922,009	281,156	30.5%
6.	Revenues from Capacity Sales	(67,410,065)	(87,720,877)	20,310,812	-23.2%
7.	Total (Lines 1 through 6)	$ 308,483,372	$ 306,337,976	$ 2,145,396	0.7%
8.	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
9.	Jurisdictional Capacity Charges	$ 299,843,401	$ 297,758,092	$ 2,085,309	0.7%
10.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (42,709,194)	(42,709,194)	0	N/A
11.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 257,134,207	$ 255,048,898	$ 2,085,309	0.8%
12.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 273,853,518	$ 266,527,861	$ 7,325,657	2.7%
13.	Prior Period True-up Provision	50,684,184	50,684,184	0	N/A
14.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 324,537,702	$ 317,212,045	$ 7,325,657	2.3%
15.	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 67,403,495	$ 62,163,147	$ 5,240,348	N/A
16.	Interest Provision for Period	3,207,632	3,243,144	(35,512)	N/A
17.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	50,684,185	50,684,185	0	N/A
18.	Deferred True-up - Over/(Under) Recovery	11,771,496	11,771,496	0	N/A
19.	Prior Period True-up Provision - Collected/(Refunded) this Period	(50,684,185)	(50,684,185)	0	N/A
20.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 82,382,624	$ 77,177,787	$ 5,204,837	N/A

Notes:
(a) Per K. M. Dubin's Testimony Appendix III, Page 7, Docket No. 980001-EI, filed October 5, 1998.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-2
DOCKET NO 99001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-68
OCTOBER 1, 1999

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2000 - December 2000

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
3	Schedule E1 Period Summary of Fuel & Purchased Power Costs and Levelized Fuel Factor	K. M. Dubin
4	Schedule E1-A Calculation of Total True-Up (Projected Period)	K. M. Dubin
5	Schedule E1-B Calculation of Estimated/Actual True-Up	K. M. Dubin
6	Schedule E1-B-1 Estimated/Actual vs. Original Projections	K. M. Dubin
7	Schedule E1-C Calculation of True up Factor	K. M. Dubin
8	Schedule E1-D Time of Use Rate Schedule	K. M. Dubin
9	Schedule E1-E Factors By Rate Group	K. M. Dubin
9a	1996 Actual Energy Losses By Rate Group	K. M. Dubin
10-11	Schedule E2 Monthly Summary of Fuel & Purchased Power Costs	Dubin/Silva/ Wade
12-15	Schedule E3 Monthly Summary of Generating System Data	R. Silva/R. Wade
16-54	Schedule E4 Monthly Generation and Fuel Cost by Unit	R. Silva/R. Wade
55-56	Schedule E5 Monthly Fuel Inventory Data	R. Silva/R. Wade
57-58	Schedule E6 Monthly Power Sold Data	R. Silva
59-60	Schedule E7 Monthly Purchased Power Data	R. Silva
61-62	Schedule E8 Energy Payment to Qualifying Facilities	R. Silva
63-64	Schedule E9 Monthly Economy Energy Purchase Data	R. Silva
65	Schedule E10 Residential Bill Comparison	K. M. Dubin
66	Schedule H1 Three Year Historical Comparison	K. M. Dubin
67-68	Cogeneration Tariff Sheets	K. M. Dubin

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1. Estimated over/(under) recovery (January 1999 - December 1999 period) (Schedule E1-B)	$	8,846,485
2. Final True-Up (April 1998 - December 1998 period)	$	33,531,098
3.Total over/(under) recovery (Lines 1 + 2) To be included in the January 2000 -December 2000 projected period (Schedule E1, Line 29)	$	42,377,583
2. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)		85,722,255
3. True-Up Factor (Lines 3/4) c/kWh:		0.0494

CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 1999
ACTUALS THROUGH AUGUST 1999 - REVISED ESTIMATES FOR SEPTEMBER THROUGH DECEMBER 1999

LINE NO.			(1) ACTUAL JANUARY	(2) ACTUAL FEBRUARY	(3) ACTUAL MARCH	(4) ACTUAL APRIL	(5) ACTUAL MAY	(6) ACTUAL JUNE
A		Fuel Costs & Net Power Transactions						
	1	a Fuel Cost of System Net Generation	$ 74,966,513	$ 67,320,325	$ 77,682,313	$ 99,379,934	$ 111,666,435	$ 119,996,633
		b Nuclear Fuel Disposal Costs	2,106,804	1,875,174	1,852,831	1,856,814	1,987,944	1,882,166
		c Coal Car Depreciation & Return	343,690	396,132	394,093	387,316	381,172	379,227
		d Gas Pipelines Depreciation & Return	203,901	252,898	251,373	247,362	243,705	242,249
		e DOE D&D Fund Payment	0	0	0	0	0	0
	2	Fuel Cost of Power Sold	(4,308,867)	(3,121,659)	(4,768,198)	(3,304,752)	(2,458,975)	(3,662,473)
	3	a Fuel Cost of Purchased Power	9,259,514	8,110,233	6,254,940	8,662,108	11,053,801	12,195,046
		b Energy Payments to Qualifying Facilities	7,384,758	7,749,274	5,808,817	8,609,956	9,620,532	10,757,920
	4	Energy Cost of Economy Purchases	307,965	379,173	779,202	8,763,674	10,746,186	2,248,603
	5	Total Fuel Costs & Net Power Transactions	$ 90,264,278	$ 82,961,550	$ 88,255,371	$ 124,602,412	$ 143,240,800	$ 144,039,371
	6	Adjustments to Fuel Cost:						
		a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,335,793)	(1,167,099)	(1,097,571)	(1,283,761)	(1,836,345)	(2,063,822)
		b Reactive and Voltage Control Fuel Revenue	(34,993)	0	0	0	0	0
		c Inventory Adjustments	42,686	(28,494)	(8,990)	31,201	73,835	47,237
		d Non Recoverable Oil/Tank Bottoms	(268,274)	10,467	0	308,803	0	27,340
		e Modifications to Burn Low Gravity Oil	2,270	33,042	16,380	8,788	30,294	3,619
		f Cedar Bay	0	0	0	0	0	0
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 88,670,174	$ 81,809,466	$ 87,165,190	$ 123,667,443	$ 141,508,584	$ 142,053,745
B		kWh Sales						
	1	Jurisdictional kWh Sales (RTP @ CBL) (a)	6,693,125,011	5,874,423,176	5,779,697,289	6,240,929,428	6,840,110,582	7,365,928,534
	2	Sale for Resale (excluding FKEC & CKW)	5,741,465	1,699,476	993,364	1,219,334	1,129,109	1,063,380
	3	Sub-Total Sales (excluding FKEC & CKW)	6,698,866,476	5,876,122,652	5,780,690,653	6,242,148,762	6,841,239,691	7,366,991,914
		Jurisdictional % of Total kWh Sales (lines B1/B3)	99.91429 %	99.97108 %	99.98282 %	99.98047 %	99.98350 %	99.98557 %
C		True-up Calculation						
	1	Jurisdictional Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 130,182,678	$ 114,294,370	$ 112,326,533	$ 121,446,215	$ 133,250,111	$ 143,511,159
	2	Fuel Adjustment Revenues Not Applicable to Period:						
		a Prior Period True-up Provision	(9,639,932)	(9,639,932)	(9,639,932)	(9,639,932)	(9,639,932)	(9,639,932)
		b GPIF, Net of Revenue Taxes (b)	(767,243)	(767,243)	(767,243)	(767,243)	(767,243)	(767,243)
		c Oil Backout Revenues, Net of revenue Taxes	13	71	7	18	24	(27)
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 119,775,516	$ 103,887,266	$ 101,919,365	$ 111,039,058	$ 122,842,960	$ 133,103,957
	4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 88,670,174	$ 81,809,466	$ 87,165,190	$ 123,667,443	$ 141,508,584	$ 142,053,745
		b Nuclear Fuel Expense - 100% Retail	0	0	0	0	0	0
		c RTP Incremental Fuel -100% Retail	110,086	36,348	15,590	64,544	142,821	151,916
		d D&D Fund Payments -100% Retail	0	0	0	0	0	0
		e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	88,560,088	81,773,118	87,149,600	123,602,899	141,365,763	141,901,829
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.91429 %	99.97108 %	99.98282 %	99.98047 %	99.98350 %	99.98557 %
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00063) +(Lines C4b,c,d)	$ 88,650,014	$ 81,837,319	$ 87,205,112	$ 123,721,158	$ 141,574,304	$ 142,122,654
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 31,125,502	$ 22,049,947	$ 14,714,253	$ (12,682,100)	$ (18,731,344)	$ (9,018,697)
	8	Interest Provision for the Month (Line D10)	(249,890)	(103,795)	8,638	51,607	27,261	10,611
	9	True-up & Interest Provision Beg of Period-Over/(Under) Recovery	(115,679,187)	(75,163,643)	(43,577,558)	(19,214,735)	(22,205,297)	(31,269,448)
		a Deferred True-up Beginning of Period - Over/(Under) Recovery	33,531,098	33,531,098	33,531,098	33,531,098	33,531,098	33,531,098
	10	Prior Period True-up Collected/(Refunded) This Period	9,639,932	9,639,932	9,639,932	9,639,932	9,639,932	9,639,932
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (41,632,545)	$ (10,046,461)	$ 14,316,363	$ 11,325,802	$ 2,261,650	$ 2,893,496

NOTES
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
(b) Generation Performance Incentive Factor is (($9,353,960/12) x 98.4280%) - See Order No. PSC-98-1715-FOF-EI.
(c) Jurisdictional Loss Multiplier per Schedule E2 filed October 5, 1998.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCE
FOR THE PERIOD JANUARY THROUGH DECEMBER 1999

	LINE NO.			(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	1	a	Fuel Cost of System Net Generation	$ 1,241,765,065	$ 1,189,922,690	$ 51,842,375	4.4 %
		b	Nuclear Fuel Disposal Costs	22,527,680	21,931,733	595,947	2.7 %
		c	Coal Cars Depreciation & Return	4,516,155	4,612,107	(95,952)	(2.1) %
		d	Gas Pipelines Depreciation & Return	2,864,415	2,998,046	(133,631)	(2.3) %
		e	DOE D&D Fund Payment	5,753,000	5,753,000	0	0.0 %
	2		Fuel Cost of Power Sold	(50,568,637)	(50,840,162)	271,525	(0.5) %
	3	a	Fuel Cost of Purchased Power	140,826,489	133,556,710	7,269,779	5.4 %
		b	Energy Payments to Qualifying Facilities	112,122,785	146,348,781	(34,225,996)	(23.4) %
	4		Energy Cost of Economy Purchases	45,874,932	69,178,210	(23,303,278)	(33.7) %
	5		Total Fuel Costs & Net Power Transactions	$ 1,525,681,884	$ 1,523,461,115	$ 2,220,769	0.1 %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (20,640,846)	$ (22,169,994)	$ 1,529,148	(6.9) %
		b	Reactive and Voltage Control Fuel Revenue	(34,993)	0	(34,993)	N/A
		c	Inventory Adjustments	217,570	0	217,570	N/A
		d	Non Recoverable Oil/Tank Bottoms	(95,673)	0	(95,673)	N/A
		e	Modifications to Burn Low Gravity Oil	104,202	0	104,202	N/A
		f	Cedar Bay	5,065,558	0	5,065,558	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 1,510,297,702	$ 1,501,291,121	$ 9,006,581	0.6 %
C	1		Jurisdictional kWh Sales	84,534,363,696	83,614,990,000	919,373,696	1.1 %
	2		Sale for Resale	15,218,212	35,906,000	(20,687,788)	(57.6) %
	3		Total Sales (Excluding RTP Incremental)	84,549,581,908	83,650,896,000	898,685,908	1.1 %
	4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 1,644,886,357	1,626,177,224	$ 18,709,133	1.2 %
		a	Prior Period True-up Provision	(115,679,187)	(115,679,187)	0	0.0 %
		b	Generation Performance Incentive Factor Net (b)	(9,206,916)	(9,206,916)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue Taxes	171	0	171	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 1,520,000,425	$ 1,501,291,121	$ 18,709,304	1.2 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 1,510,297,702	$ 1,501,291,121	$ 9,006,581	0.6 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	614,183	0	614,183	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 e)	0	0	0	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	1,509,683,519	1,501,291,121	8,392,398	0.6 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 1,511,005,012	$ 1,501,291,121	$ 9,713,891	0.6 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ 8,995,413	$ 0	$ 8,995,413	N/A
	8		Interest Provision for the Month	(148,928)	0	(148,928)	N/A
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(115,679,187)	(115,679,187)	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	33,531,098	0	33,531,098	N/A
	10		Prior Period True-up Collected/(Refunded) This Period	115,679,187	115,679,187	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ 42,377,582	$ 0	$ 42,377,582	N/A

NOTES (a) Per Estimated Schedule E-2, filed October 5, 1998.

(b) Generation Performance Incentive Factor is (($9,353,960/12) x 98.4280%) - See Order No. PSC-98-1715-FOF-EI.

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1. TOTAL AMOUNT OF ADJUSTMENTS:	(54,783,218)
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$11,367,066
B. TRUE-UP (OVER)/UNDER RECOVERED	$ (66,150,284)
2. TOTAL JURISDICTIONAL SALES (MWH)	85,722,255
3. ADJUSTMENT FACTORS c/kWh:	(0.0639)
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0133
B. TRUE-UP FACTOR	(0.0772)

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2000 - DECEMBER 2000

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.61	33.38
OFF PEAK	69.39	66.62
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$1,628,525,428	$543,601,788	$1,084,923,640
2	MWH SALES	85,729,426	26,241,777	59,487,649
3	COST PER KWH SOLD	1.8996	2.0715	1.8238
4	JURISDICTIONAL LOSS FACTOR	1.00064	1.00064	1.00064
5	JURISDICTIONAL FUEL FACTOR	1.9008	2.0728	1.8249
6	TRUE-UP	(0.0494)	(0.0494)	(0.0494)
7				
8	TOTAL	1.8514	2.0234	1.7755
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	1.8810	2.0557	1.8039
11	GPIF	0.0133	0.0133	0.0133
12	RECOVERY FACTOR including GPIF	1.8943	2.0690	1.8172
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	1.894	2.069	1.817

HOURS:		
	ON-PEAK	24.66 %
	OFF-PEAK	75.34 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2000 - DECEMBER 2000

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		1.894	1.00225	1.899
A-1*	SL-1, OL-1, PL-1		1.857	1.00225	1.861
B	GSD-1		1.894	1.00216	1.898
C	GSLD-1 & CS-1		1.894	1.00087	1.896
D	GSLD-2, CS-2, OS-2 & MET		1.894	0.99510	1.885
E	GSLD-3 & CS-3		1.894	0.95792	1.815
A	RST-1, GST-1	ON-PEAK	2.069	1.00225	2.074
		OFF-PEAK	1.817	1.00225	1.821
B	GSDT-1	ON-PEAK	2.069	1.00216	2.073
	CILC-1(G)	OFF-PEAK	1.817	1.00216	1.821
C	GSLDT-1 &	ON-PEAK	2.069	1.00087	2.071
	CST-1	OFF-PEAK	1.817	1.00087	1.819
D	GSLDT-2 &	ON-PEAK	2.069	0.99510	2.059
	CST-2	OFF-PEAK	1.817	0.99510	1.808
E	GSLDT-3,CST-3,	ON-PEAK	2.069	0.95792	1.982
	CILC -1(T)	OFF-PEAK	1.817	0.95792	1.741
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	2.069	0.99465	2.058
	ISST-1(D)	OFF-PEAK	1.817	0.99465	1.807

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

Florida Power & Light Company
1998 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	45,447,353	1.070146277	48,635,316	0.934452	3,187,963	1.00225
2							
3	GS-1 Sec	5,247,294	1.070146277	5,615,372	0.934452	368,078	1.00225
4							
5	GSD-1 Pri	71,994	1.044344811	75,176	0.957538	3,182	
6	GSD-1 Sec	19,173,987	1.070146277	20,518,864	0.934452	1,344,877	
7	Subtot GSD-1	19,245,872	1.070049774	20,594,041	0.934536	1,348,169	1.00216
8							
9	OS-2 Pri	22,276	1.044344811	23,263	0.957538	988	0.97808
10							
11	GSLD-1 Pri	415,401	1.044344811	433,822	0.957538	18,421	
12	GSLD-1 Sec	7,268,885	1.070146277	7,776,386	0.934452	508,730	
13	Subtot GSLD-1	7,682,086	1.068751086	8,210,216	0.935672	526,150	1.00084
14							
15	CS-1 Pri	37,995	1.044344811	39,838	0.957538	1,883	
16	CS-1 Sec	211,838	1.070146277	226,483	0.934452	14,646	
17	Subtot CS-1	249,583	1.068222722	266,121	0.937880	16,529	0.99857
18							
19	Subtot GSLD1 / CS1	7,931,669	1.068871534	8,476,338	0.935741	544,679	1.00067
20							
21	GSLD-2 Pri	210,704	1.044344811	220,048	0.957538	9,344	
22	GSLD-2 Sec	760,165	1.070146277	834,891	0.934452	54,726	
23	Subt GSLDT-2	980,869	1.064858710	1,054,939	0.936267	84,069	0.99711
24							
25	CS-2 Pri	42,840	1.044344811	44,731	0.957538	1,891	
26	CS-2 Sec	69,994	1.070146277	74,883	0.934452	4,889	
27	Subtot CST-2	112,834	1.060377782	119,424	0.943080	6,800	0.98510
28							
29	Subtot GSLD2 / CS2	1,103,483	1.064222691	1,174,363	0.939853	70,869	0.99870
30							
31	GSLD-3 Trn	672,507	1.022816224	687,851	0.977883	15,344	0.95792
32							
33	CS-3 Trn	0	1.022816224	0	0.000000	0	0.00000
34							
35	Subtot GSLD3 / CS3	672,507	1.022816224	687,851	0.977883	15,344	0.95792
36							
37	ISST-1 Sec	0	1.070146277	0	0.000000	0	0.00000
38							
39	SST-1 Pri	39,913	1.044344811	41,683	0.957538	1,770	
40	SST-1 Sec	14,083	1.070146277	15,071	0.934452	988	
41	SST-1 (D)	53,996	1.051074226	56,754	0.951408	2,758	0.98438
42							
43	SST-1 Trn	99,599	1.022816224	101,831	0.977883	2,272	0.95792
44							
45	CILC D Pri	869,886	1.044344811	929,452	0.957538	39,466	
46	CILC D Sec	1,940,342	1.070146277	2,078,343	0.934452	138,101	
47	CILC D	2,830,228	1.062033917	3,005,795	0.941580	175,567	0.99485
48							
49	CILC G Sec	342,138	1.070146277	359,125	0.934452	16,885	1.00225
50							
51	Subtot CILC D / CILC G	3,072,366	1.062672252	3,264,918	0.941034	192,552	0.99525
52							
53	CILC T Trn	1,224,470	1.022816224	1,252,408	0.977883	27,939	0.95792
54							
55	ISST-D & CILC-D	2,830,228	1.062033917	3,005,795	0.941580	175,567	0.99485
56							
57	GSD-1 & CILC-1(G)	19,489,010	1.070050973	20,853,164	0.934535	1,365,154	1.00216
58							
59	MET Pri	81,156	1.044344811	84,755	0.957538	3,599	0.97808
60							
61	OS-2, GSLD2, CS2, & MET	1,206,925	1.062519190	1,282,381	0.941158	75,456	0.99510
62							
63	OL-1 Sec	108,790	1.070146277	116,421	0.934452	7,631	1.00225
64							
65	SL-1 Sec	337,304	1.070146277	360,984	0.934452	23,681	1.00225
66							
67	Subtot OL1 / SL1	446,094	1.070146277	477,386	0.934452	31,292	1.00225
68							
69	SL-2 Sec	79,468	1.070146277	85,073	0.934452	5,576	1.00225
70							
71	RTP-1 Pri	18,806	1.044344811	19,744	0.957538	938	
72	RTP-1 Sec	133,276	1.070146277	142,624	0.934452	9,348	
73	Subtot RTP-1	152,183	1.068940848	162,370	0.937259	10,187	0.99825
74							
75	RTP-2 Pri	82,741	1.044344811	86,853	0.957538	4,113	
76	RTP-2 Sec	134,327	1.070146277	143,749	0.934452	9,423	
77	Subtot RTP-2	227,068	1.059808232	240,603	0.943745	13,535	0.98238
78							
79	RTP-3 Trn	36,973	1.022816224	37,817	0.977883	844	0.95792
80							
81	Total FPSC	85,143,814	1.068432648	90,970,456	0.935850	5,826,642	1.00084
82							
83	Total FERC Sales	1,319,609	1.023138134	1,350,142	0.977385	30,533	
84							
85	Total Company	86,463,423	1.067741656	92,320,598	0.936556	5,857,175	
86							
87	Company Use	166,755	1.070146277	178,452	0.934452	11,697	
88							
89	Total FPL	86,630,178	1.067748265	92,499,051	0.936552	5,868,873	1.00000
90							
91	Summary of Sales by Voltage						
92							
93	Transmission	3,333,366	1.022816224	3,409,442	0.977883	76,055	
94							
95	Primary	1,943,394	1.044344811	2,029,573	0.957538	86,179	
96							
97	Secondary	81,186,642	1.070146277	86,991,583	0.934452	5,804,941	
98							
99	Total	86,463,423	1.067741656	92,320,598	0.936556	5,857,175	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

SCHEDULE E2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	*FUEL COST OF SYSTEM GENERATION*	$86,331,150	$76,116,490	$92,155,530	$93,751,690	$122,714,450	$134,124,890	$605,194,200	A1
1a	NUCLEAR FUEL DISPOSAL	1,984,495	1,825,992	1,512,225	1,631,527	1,617,228	1,873,363	10,444,830	1a
1b	COAL CAR INVESTMENT	373,346	371,324	369,303	367,282	353,413	341,438	2,176,106	1b
1c	NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	0	1c
1d	GAS LATERAL ENHANCEMENTS	236,250	234,753	233,256	231,759	230,262	228,765	1,395,045	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1f	*LOW GRAVITY FUEL MODIFICATIONS*	0	0	0	0	0	0	0	1f
1g	LAST CORE	406,363	406,363	406,363	406,363	406,363	406,363	2,438,175	1g
2	FUEL COST OF POWER SOLD	(6,088,936)	(4,818,830)	(7,209,933)	(3,117,065)	(3,304,979)	(4,652,025)	(29,191,768)	2
3	FUEL COST OF PURCHASED POWER	17,920,390	15,856,690	16,089,840	11,782,930	13,825,770	12,599,970	88,075,590	3
3a	MISSION SETTLEMENT	0	147,000	0	1,108,357	0	0	1,255,357	3a
3b	QUALIFYING FACILITIES	9,993,623	8,641,208	9,615,741	10,216,975	11,038,972	11,319,311	60,825,830	3b
4	ENERGY COST OF ECONOMY PURCHASES	3,987,930	3,202,090	2,822,890	3,993,270	4,251,340	2,300	18,259,820	4
4a	FUEL COST OF SALES TO FKEC / CKW	(1,735,448)	(1,740,104)	(1,742,012)	(1,819,943)	(1,855,717)	(2,012,352)	(10,905,577)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$113,409,163	$100,242,975	$114,253,202	$118,553,144	$149,277,101	$154,232,023	$749,967,608	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	6,522,973	6,577,520	5,769,608	6,318,418	6,913,643	7,724,447	39,826,609	6
7	COST PER KWH SOLD (¢/KWH)	1.7386	1.5240	1.9803	1.8763	2.1592	1.9967	1.8831	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00064	1.00064	1.00064	1.00064	1.00064	1.00064	1.00064	7a
7b	JURISDICTIONAL COST (¢/KWH)	1.7397	1.5250	1.9815	1.8775	2.1605	1.9980	1.8843	7b
9	TRUE-UP (¢/KWH)	(0.0541)	(0.0537)	(0.0612)	(0.0559)	(0.0511)	(0.0457)	(0.0532)	9
10	TOTAL	1.6856	1.4713	1.9203	1.8216	2.1094	1.9523	1.8311	10
11	REVENUE TAX FACTOR 0.01597	0.0269	0.0235	0.0307	0.0291	0.0337	0.0312	0.0292	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	1.7125	1.4948	1.9510	1.8507	2.1431	1.9835	1.8603	12
13	GPIF (¢/KWH)	0.0145	0.0144	0.0164	0.0150	0.0137	0.0123	0.0143	13
14	RECOVERY FACTOR including GPIF	1.7270	1.5092	1.9674	1.8657	2.1568	1.9958	1.8746	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	1.727	1.509	1.967	1.866	2.157	1.996	1.875	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2000 - DECEMBER 2000

SCHEDULE E2
Page 2 of 2

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$154,417,930	$151,542,860	$129,706,410	$118,040,890	$85,804,090	$89,007,900	$1,333,714,280	A1
1a	NUCLEAR FUEL DISPOSAL	1,935,808	1,935,808	1,873,363	1,494,071	1,844,304	1,984,495	$21,512,679	1a
1b	COAL CAR INVESTMENT	339,634	337,829	336,025	334,220	332,416	330,612	$4,186,842	1b
1c	NUCLEAR THERMAL UPRATE	0	0	0	0	0	0	$0	1c
1d	GAS LATERAL ENHANCEMENTS	227,268	225,771	224,274	222,777	221,280	219,783	$2,736,198	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	5,926,000	0	$5,926,000 $0	1e
1f	LOW GRAVITY FUEL MODIFICATIONS	0	0	0	0	0	0	$0	1f
1g	LAST CORE	406,363	406,363	406,363	406,363	406,363	406,363	$4,876,351	1g
2	FUEL COST OF POWER SOLD	(6,543,775)	(5,953,766)	(4,503,690)	(1,581,033)	(1,436,290)	(1,372,630)	($50,582,952)	2
3	FUEL COST OF PURCHASED POWER	12,886,640	13,004,640	13,066,970	15,831,810	15,758,990	16,415,950	$175,040,590	3
3a	MISSION SETTLEMENT	0	0	0	1,108,357	147,000	0	$2,510,715	3a
3b	QUALIFYING FACILITIES	12,126,687	11,648,742	11,062,787	11,366,584	7,564,619	7,841,415	$122,436,664	3b
4	ENERGY COST OF ECONOMY PURCHASES	2,300	2,300	6,900	4,826,780	3,542,710	3,265,990	$29,906,800	4
4a	FUEL COST OF SALES TO FKEC / CKW	(2,123,150)	(2,257,888)	(2,313,469)	(2,220,365)	(2,066,297)	(1,851,992)	($23,738,738)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$173,675,705	$170,892,659	$149,885,933	$149,830,454	$118,045,184	$116,247,885	$1,628,525,428	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,027,444	8,128,514	8,251,984	7,957,226	6,721,706	6,815,942	85,729,425	6
7	COST PER KWH SOLD (¢/KWH)	2.1635	2.1024	1.8161	1.8829	1.7562	1.7055	1.8996	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00064	1.00064	1.00064	1.00064	1.00064	1.00064	1.00064	7a
7b	JURISDICTIONAL COST (¢/KWH)	2.1649	2.1037	1.8173	1.8842	1.7573	1.7066	1.9006	7b
9	TRUE-UP (¢/KWH)	(0.0440)	(0.0434)	(0.0428)	(0.0444)	(0.0525)	(0.0518)	(0.0494)	9
10	TOTAL	2.1209	2.0603	1.7745	1.8398	1.7048	1.6548	1.8514	10
11	REVENUE TAX FACTOR 0.01597	0.0339	0.0329	0.0283	0.0294	0.0272	0.0264	0.0296	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	2.1548	2.0932	1.8028	1.8692	1.7320	1.6812	1.8810	12
13	GPIF (¢/KWH)	0.0118	0.0117	0.0115	0.0119	0.0141	0.0139	0.0133	13
14	RECOVERY FACTOR including GPIF	2.1666	2.1049	1.8143	1.8811	1.7461	1.6951	1.8943	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	2.167	2.105	1.814	1.881	1.746	1.695	1.894	15

Generating System Comparative Data by Fuel Type

		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$28,772,750	$23,510,320	$40,219,130	$36,861,060	$63,638,880	$62,922,110
2	Light Oil	$261,510	$58,230	$335,520	$540	$346,300	$936,130
3	Coal	$9,139,820	$8,154,920	$8,079,220	$8,888,240	$9,261,990	$8,975,790
4	Gas	$41,603,920	$38,347,010	$38,370,210	$42,523,740	$44,063,760	$54,934,080
5	Nuclear	$6,553,150	$6,046,010	$5,151,450	$5,478,110	$5,403,520	$6,356,780
6	***Total***	$86,331,150	$76,116,490	$92,155,530	$93,751,690	$122,714,450	$134,124,890
	System Net Generation (MWH)						
7	Heavy Oil	1,163,324	943,975	1,689,550	1,476,757	2,515,677	2,471,522
8	Light Oil	4,108	1,129	6,772	10	6,651	18,948
9	Coal	603,976	537,100	515,135	581,727	605,841	586,960
10	Gas	1,368,833	1,505,936	1,525,791	1,612,038	1,630,842	2,069,277
11	Nuclear	2,129,286	1,959,219	1,622,559	1,750,565	1,735,223	2,010,046
12	***Total***	5,269,527	4,947,359	5,359,807	5,421,097	6,494,234	7,156,753
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	1,879,800	1,530,123	2,667,390	2,328,921	3,949,359	3,892,342
14	Light Oil (BBLS)	10,924	2,570	15,472	24	15,712	44,769
15	Coal (TONS)	317,306	283,170	280,982	308,446	321,408	311,397
16	Gas (MCF)	10,435,143	11,522,677	11,821,410	13,418,232	12,819,118	17,466,386
17	Nuclear (MBTU)	21,386,308	19,701,574	16,658,773	17,836,594	17,593,734	20,607,094
	BTU Burned (MMBTU)						
18	Heavy Oil	12,030,719	9,792,789	17,071,300	14,905,094	25,275,898	24,910,986
19	Light Oil	63,497	14,909	89,736	139	91,131	259,662
20	Coal	6,078,105	5,413,674	5,224,620	5,912,736	6,157,240	5,965,409
21	Gas	10,435,143	11,522,677	11,821,410	13,418,232	12,819,118	17,466,386
22	Nuclear	21,386,308	19,701,574	16,658,773	17,836,594	17,593,734	20,607,094
23	***Total***	49,993,772	46,445,622	50,865,839	52,072,795	61,937,121	69,209,537

Generating System Comparative Data by Fuel Type

		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00
	Generation Mix (%MWH)						
24	Heavy Oil	22.08%	19.08%	31.52%	27.24%	38.74%	34.53%
25	Light Oil	0.08%	0.02%	0.13%	0.00%	0.10%	0.26%
26	Coal	11.46%	10.86%	9.61%	10.73%	9.33%	8.20%
27	*Gas*	25.98%	30.44%	28.47%	29.74%	25.11%	28.91%
28	Nuclear	40.41%	39.60%	30.27%	32.29%	26.72%	28.09%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	15.3063	15.3650	15.0781	15.8275	16.1137	16.1656
31	Light Oil ($/BBL)	23.9390	22.6576	21.6856	22.5000	22.0405	20.9102
32	Coal ($/ton)	28.8044	28.7987	28.7535	28.8162	28.8169	28.8243
33	Gas ($/MCF)	3.9869	3.3280	3.2458	3.1691	3.4373	3.1451
34	Nuclear ($/MBTU)	0.3064	0.3069	0.3092	0.3071	0.3071	0.3085
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	2.3916	2.4008	2.3560	2.4731	2.5178	2.5259
36	Light Oil	4.1185	3.9057	3.7390	3.8765	3.8000	3.6052
37	Coal	1.5037	1.5064	1.5464	1.5032	1.5042	1.5046
38	Gas	3.9869	3.3280	3.2458	3.1691	3.4373	3.1451
39	Nuclear	0.3064	0.3069	0.3092	0.3071	0.3071	0.3085
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,342	10,374	10,104	10,093	10,047	10,079
41	Light Oil	15,457	13,205	13,251	13,930	13,702	13,704
42	Coal	10,063	10,079	10,142	10,164	10,163	10,163
43	*Gas*	7,623	7,652	7,748	8,324	7,860	8,441
44	Nuclear	10,044	10,056	10,267	10,189	10,139	10,252
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	2.4733	2.4906	2.3805	2.4961	2.5297	2.5459
46	Light Oil	6.3659	5.1577	4.9545	5.4000	5.2067	4.9405
47	Coal	1.5133	1.5183	1.5684	1.5279	1.5288	1.5292
48	Gas	3.0394	2.5464	2.5148	2.6379	2.7019	2.6547
49	Nuclear	0.3078	0.3086	0.3175	0.3129	0.3114	0.3163
50	***Total***	1.6383	1.5385	1.7194	1.7294	1.8896	1.8741

Generating System Comparative Data by Fuel Type

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
Fuel Cost of System Net Generation ($)							
1 Heavy Oil	$87,501,030	$84,871,910	$56,905,550	$52,291,140	$29,620,940	$31,815,230	$598,930,050
2 Light Oil	$2,472,010	$4,097,500	$1,622,510	$2,315,280	$62,890	$110	$12,508,530
3 Coal	$9,285,620	$9,296,500	$8,994,010	$9,308,180	$8,824,510	$9,169,580	$107,378,380
4 Gas	$48,683,570	$46,801,410	$55,918,370	$49,046,060	$41,195,520	$41,466,560	$542,954,210
5 Nuclear	$6,475,700	$6,475,540	$6,265,970	$5,080,230	$6,100,230	$6,556,420	$71,943,110
6 *Total*	$154,417,930	$151,542,860	$129,706,410	$118,040,890	$85,804,090	$89,007,900	$1,333,714,280
System Net Generation (MWH)							
7 Heavy Oil	3,399,546	3,400,572	2,321,801	2,045,126	1,154,218	1,293,562	23,875,630
8 Light Oil	49,349	80,693	30,201	41,609	1,235	2	240,707
9 Coal	606,573	606,573	586,040	605,726	579,644	601,188	7,016,483
10 Gas	1,775,273	1,797,903	2,230,902	1,857,603	1,525,242	1,442,022	20,341,662
11 Nuclear	2,077,047	2,077,047	2,010,046	1,603,081	1,978,867	2,129,286	23,082,272
12 *Total*	7,907,788	7,962,788	7,178,990	6,153,145	5,239,206	5,466,060	74,556,754
Units of Fuel Burned							
13 Heavy Oil (BBLS)	5,350,422	5,342,718	3,643,170	3,209,448	1,826,666	2,066,260	37,686,619
14 Light Oil (BBLS)	117,137	192,868	71,697	99,164	2,820	5	573,162
15 Coal (TONS)	321,721	321,637	310,628	320,972	303,691	315,046	3,716,404
16 Gas (MCF)	14,365,517	14,748,150	19,349,854	15,484,197	11,745,653	11,012,332	164,188,669
17 Nuclear (MBTU)	21,294,000	21,294,000	20,607,094	16,739,184	19,933,950	21,386,308	235,038,613
BTU Burned (MMBTU)							
18 Heavy Oil	34,242,700	34,193,392	23,316,286	20,540,470	11,690,666	13,224,061	241,194,361
19 Light Oil	679,620	1,119,537	415,986	575,500	16,357	31	3,326,104
20 Coal	6,164,749	6,164,749	5,956,272	6,156,146	5,832,609	6,050,120	71,076,425
21 Gas	14,365,517	14,748,150	19,349,854	15,484,197	11,745,653	11,012,332	164,188,669
22 Nuclear	21,294,000	21,294,000	20,607,094	16,739,184	19,933,950	21,386,308	235,038,613
23 *Total*	76,746,585	77,519,828	69,645,491	59,495,497	49,219,234	51,672,852	714,824,172

Generating System Comparative Data by Fuel Type

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
Generation Mix (%MWH)							
24 Heavy Oil	42.99%	42.71%	32.34%	33.24%	22.03%	23.67%	32.02%
25 Light Oil	0.62%	1.01%	0.42%	0.68%	0.02%	0.00%	0.32%
26 Coal	7.67%	7.62%	8.16%	9.84%	11.06%	11.00%	9.41%
27 Gas	22.45%	22.58%	31.08%	30.19%	29.11%	26.38%	27.28%
28 Nuclear	26.27%	26.08%	28.00%	26.05%	37.77%	38.95%	30.96%
29 ***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Cost per Unit							
30 Heavy Oil ($/BBL)	16.3540	15.8855	15.6198	16.2929	16.2158	15.3975	15.8924
31 Light Oil ($/BBL)	21.1036	21.2451	22.6301	23.3480	22.3014	22.0000	21.8237
32 Coal ($/ton)	28.8623	28.9037	28.9543	29.0000	29.0575	29.1055	28.8931
33 Gas ($/MCF)	3.3889	3.1734	2.8899	3.1675	3.5073	3.7655	3.3069
34 Nuclear ($/MBTU)	0.3041	0.3041	0.3041	0.3035	0.3060	0.3066	0.3061
Fuel Cost per MMBTU ($/MMBTU)							
35 Heavy Oil	2.5553	2.4821	2.4406	2.5458	2.5337	2.4059	2.4832
36 Light Oil	3.6373	3.6600	3.9004	4.0231	3.8449	3.5831	3.7607
37 Coal	1.5062	1.5080	1.5100	1.5120	1.5130	1.5156	1.5107
38 Gas	3.3889	3.1734	2.8899	3.1675	3.5073	3.7655	3.3069
39 Nuclear	0.3041	0.3041	0.3041	0.3035	0.3060	0.3066	0.3061
BTU burned per KWH (BTU/KWH)							
40 Heavy Oil	10,073	10,055	10,042	10,044	10,129	10,223	10,102
41 Light Oil	13,772	13,874	13,774	13,831	13,244	15,350	13,818
42 Coal	10,163	10,163	10,164	10,163	10,062	10,064	10,130
43 Gas	8,092	8,203	8,674	8,336	7,701	7,637	8,072
44 Nuclear	10,252	10,252	10,252	10,442	10,073	10,044	10,183
Generated Fuel Cost per KWH (cents/KWH)							
45 Heavy Oil	2.5739	2.4958	2.4509	2.5569	2.5663	2.4595	2.5085
46 Light Oil	5.0092	5.0779	5.3724	5.5644	5.0923	5.5000	5.1966
47 Coal	1.5308	1.5326	1.5347	1.5367	1.5224	1.5252	1.5304
48 Gas	2.7423	2.6031	2.5065	2.6403	2.7009	2.8756	2.6692
49 Nuclear	0.3118	0.3118	0.3117	0.3169	0.3083	0.3079	0.3117
50 ***Total***	1.9527	1.9031	1.8068	1.9184	1.6377	1.6284	1.7889

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 1

Estimated For The Period of : Jan-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	404	31,592	10.5	86.8	38.6	10,531	Heavy Oil BBLS ->	51,150	6,400,002	327,358	818,010	2.5893
3	TRKY O 2	403	37,417	12.5	92.1	40.0	10,478	Heavy Oil BBLS ->	59,937	6,399,996	383,599	958,545	2.5618
5	TRKY N 3	717	506,727	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,727,536	1,000,000	4,727,536	1,402,187	0.2767
7	TRKY N 4	717	506,727	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,727,536	1,000,000	4,727,536	1,398,878	0.2761
9	FT LAUD4	452	295,800	88.0	91.9	93.3	7,780	Gas MCF ->	2,301,204	1,000,000	2,301,204	7,320,130	2.4747
11	FT LAUD5	452	289,702	86.1	91.9	92.2	7,819	Gas MCF ->	2,264,618	1,000,000	2,264,618	7,203,750	2.4866
13	PT EVER1	212	1,483	.9	92.9	40.0	11,749	Heavy Oil BBLS ->	2,650	6,400,083	16,962	43,091	2.9059
15	PT EVER2	212	2,759	1.7	92.6	55.5	10,970	Heavy Oil BBLS ->	4,632	6,400,047	29,646	75,318	2.7296
17	PT EVER3	406	73,823	24.4	95.8	37.5	10,879	Heavy Oil BBLS ->	124,191	6,399,999	794,824	2,019,280	2.7353
19	PT EVER4	402	61,468	20.6	88.6	41.5	10,604	Heavy Oil BBLS ->	100,411	6,399,998	642,633	1,632,633	2.6561
21	RIV 3	282	84,098	40.1	78.3	50.3	10,604	Heavy Oil BBLS ->	138,260	6,399,998	884,862	2,059,278	2.4487
23	RIV 4	282	98,001	46.7	92.5	55.3	10,421	Heavy Oil BBLS ->	158,975	6,399,999	1,017,441	2,367,820	2.4161
25	ST LUC 1	853	602,816	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,445,699	1,000,000	6,445,699	2,025,239	0.3360
27	ST LUC 2	726	513,017	95.0	85.9	100.0	10,693	Nuclear MBTU ->	5,485,540	1,000,000	5,485,540	1,726,848	0.3366
29	CAP CN 1	391	91,190	31.3	94.4	42.0	10,274	Heavy Oil BBLS ->	145,454	6,400,001	930,904	2,300,044	2.5223

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 2

Estimated For The Period of : Jan-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	400	73,085	24.6	81.0	42.0	10,513	Heavy Oil BBLS ->	119,122	6,399,999	762,380	1,883,662	2.5774
32													
33	SANFRD 3	147	6,355	5.8	97.4	54.5	11,519	Heavy Oil BBLS ->	10,992	6,400,004	70,348	169,618	2.6689
34													
35	SANFRD 4	385	111,389	38.9	94.5	49.0	10,692	Heavy Oil BBLS ->	185,350	6,400,001	1,186,238	2,860,164	2.5677
36													
37	SANFRD 5	385	94,174	32.9	94.5	47.0	10,909	Heavy Oil BBLS ->	159,583	6,399,998	1,021,330	2,462,550	2.6149
38													
39	PUTNAM 1	250	47,493	25.5	90.7	69.0	8,614	Gas MCF ->	405,292	1,000,000	405,292	1,289,233	2.7146
40													
41	PUTNAM 2	250	42,100	22.6	87.8	68.3	8,639	Gas MCF ->	359,973	1,000,000	359,973	1,145,073	2.7199
42													
43	MANATE 1	800	13,318	2.2	94.2	35.3	11,137	Heavy Oil BBLS ->	23,176	6,400,003	148,324	365,076	2.7413
44													
45	MANATE 2	799	51,529	8.7	82.8	39.6	11,196	Heavy Oil BBLS ->	90,144	6,400,003	576,919	1,419,997	2.7557
46													
47	FT MY 1	142	57,561	54.5	95.8	68.1	10,522	Heavy Oil BBLS ->	94,631	6,399,997	605,640	1,371,094	2.3820
48													
49	FT MY 2	400	244,103	82.0	94.0	87.3	9,498	Heavy Oil BBLS ->	362,283	6,400,001	2,318,608	5,249,042	2.1503
50													
51	CUTLER 5	72	162	.3	97.9	32.4	15,741	Gas MCF ->	2,395	1,000,000	2,395	7,617	4.6932
52													
53	CUTLER 6	145	683	.6	97.3	43.8	13,034	Gas MCF ->	8,620	1,000,000	8,620	27,420	4.0170
54													
55	MARTIN 1	821	9,912	2.3	95.4	50.0	10,650	Heavy Oil BBLS ->	16,018	6,399,985	102,516	235,232	2.3732
56			4,248					Gas MCF ->	46,132	1,000,000	46,132	146,746	3.4545
57													
58	MARTIN 2	830	20,069	4.6	95.7	43.4	10,756	Heavy Oil BBLS ->	32,842	6,399,991	210,187	482,293	2.4032
59			8,601					Gas MCF ->	94,584	1,000,000	94,584	300,872	3.4981
60													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 3

Estimated For The Period of : Jan-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	492	337,818	92.3	92.7	98.0	7,178	Gas MCF ->	2,424,778	1,000,000	2,424,778	7,713,219	2.2832
62													
63	MARTIN 4	492	340,740	93.1	91.6	98.7	7,081	Gas MCF ->	2,412,644	1,000,000	2,412,644	7,674,621	2.2523
64													
65	FM GT	624	2,810	.6	97.0	89.2	13,239	Light Oil BBLS ->	6,414	5,799,969	37,198	149,164	5.3087
66													
67	FL GT	768	389	.3	95.0	78.8	21,121	Light Oil BBLS ->	1,356	5,830,027	7,906	33,775	8.6803
68			1,444					Gas MCF ->	30,807	1,000,000	30,807	97,998	6.7870
69													
70	PE GT	384	909	.3	95.0	79.5	20,280	Light Oil BBLS ->	3,155	5,829,915	18,393	78,574	8.6440
71			42					Gas MCF ->	891	1,000,000	891	2,833	6.7613
72													
73	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,655	Coal TONS ->	33,605	25,380,037	852,894	984,367	1.1143
74													
75	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,542	Coal TONS ->	33,052	25,379,993	838,865	968,176	1.1013
76													
77	SCHER #4	578	427,731	99.4	93.3	99.4	10,255	Coal TONS ->	250,648	17,499,998	4,386,347	7,187,275	1.6803
78													
79	TOTAL	16,312	5,269,527				9,472				49,910,566	77,656,742	1.4737

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 4

Estimated For The Period of : Feb-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	404	31,630	11.2	86.8	39.0	10,478	Heavy Oil BBLS ->	50,981	6,399,997	326,276	818,039	2.5863
3	TRKY O 2	403	39,365	14.0	92.1	40.6	10,414	Heavy Oil BBLS ->	62,690	6,399,996	401,214	1,005,924	2.5554
5	TRKY N 3	717	441,342	88.4	85.9	100.0	9,330	Nuclear MBTU ->	4,117,551	1,000,000	4,117,551	1,221,677	0.2768
7	TRKY N 4	717	474,034	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,422,544	1,000,000	4,422,544	1,309,073	0.2762
9	FT LAUD4	452	287,949	91.5	91.9	96.9	7,742	Gas MCF ->	2,229,365	1,000,000	2,229,365	5,896,669	2.0478
11	FT LAUD5	452	285,890	90.9	91.9	96.2	7,776	Gas MCF ->	2,223,189	1,000,000	2,223,189	5,880,333	2.0569
13	PT EVER1	212	675	.5	92.9	54.8	11,268	Heavy Oil BBLS ->	1,164	6,399,828	7,449	18,786	2.7843
15	PT EVER2	212	883	.6	92.6	64.5	10,769	Heavy Oil BBLS ->	1,461	6,400,178	9,348	23,574	2.6710
17	PT EVER3	406	83,852	29.7	95.8	41.6	10,655	Heavy Oil BBLS ->	138,710	6,400,002	887,746	2,238,712	2.6698
19	PT EVER4	402	72,133	25.8	88.6	43.9	10,442	Heavy Oil BBLS ->	116,675	6,400,001	746,722	1,883,079	2.6106
21	RIV 3	282	49,888	25.4	78.3	41.1	10,913	Heavy Oil BBLS ->	84,030	6,400,001	537,792	1,251,106	2.5078
23	RIV 4	282	61,867	31.5	92.5	44.9	10,699	Heavy Oil BBLS ->	102,534	6,400,002	656,218	1,526,609	2.4676
25	ST LUC 1	853	563,924	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,029,847	1,000,000	6,029,847	1,898,799	0.3367
27	ST LUC 2	726	479,919	95.0	85.9	100.0	10,693	Nuclear MBTU ->	5,131,634	1,000,000	5,131,634	1,616,465	0.3368
29	CAP CN 1	391	103,638	38.1	94.4	50.8	10,111	Heavy Oil BBLS ->	162,854	6,400,002	1,042,265	2,560,453	2.4706

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 5

Estimated For The Period of : Feb-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	400	55,419	19.9	81.0	44.4	10,412	Heavy Oil BBLS ->	89,329	6,400,000	571,708	1,404,472	2.5343
32													
33	SANFRD 3	147	1,868	1.8	97.4	58.8	11,406	Heavy Oil BBLS ->	3,194	6,400,056	20,441	49,226	2.6347
34													
35	SANFRD 4	385	59,913	22.4	94.5	41.1	10,940	Heavy Oil BBLS ->	101,469	6,399,999	649,403	1,563,932	2.6103
36													
37	SANFRD 5	385	50,538	18.9	94.5	45.6	10,971	Heavy Oil BBLS ->	85,690	6,399,997	548,418	1,320,734	2.6133
38													
39	PUTNAM 1	250	145,556	83.7	90.7	88.8	8,258	Gas MCF ->	1,201,521	1,000,000	1,201,521	3,178,023	2.1834
40													
41	PUTNAM 2	250	137,188	78.8	87.8	87.9	8,273	Gas MCF ->	1,133,357	1,000,000	1,133,357	2,997,728	2.1851
42													
43	MANATE 1	800	10,173	1.8	94.2	33.7	11,298	Heavy Oil BBLS ->	17,959	6,399,994	114,934	283,337	2.7852
44													
45	MANATE 2	799	63,684	11.5	82.8	37.2	11,293	Heavy Oil BBLS ->	112,370	6,399,997	719,166	1,772,895	2.7839
46													
47	FT MY 1	142	44,882	45.4	95.8	64.2	10,654	Heavy Oil BBLS ->	74,717	6,399,996	478,187	1,081,908	2.4105
48													
49	FT MY 2	400	191,597	68.8	94.0	76.0	9,618	Heavy Oil BBLS ->	287,921	6,399,999	1,842,691	4,169,123	2.1760
50													
51	CUTLER 5	72	76	.2	97.9	53.5	14,562	Gas MCF ->	1,023	1,000,000	1,023	2,706	3.5699
52													
53	CUTLER 6	145	294	.3	97.3	69.4	12,448	Gas MCF ->	3,572	1,000,000	3,572	9,447	3.2100
54													
55	MARTIN 1	821	2,054	.5	95.4	61.0	10,413	Heavy Oil BBLS ->	3,254	6,399,932	20,827	48,166	2.3446
56			880					Gas MCF ->	9,372	1,000,000	9,372	24,790	2.8158
57													
58	MARTIN 2	830	19,915	4.9	95.7	38.9	10,982	Heavy Oil BBLS ->	33,122	6,399,995	211,983	490,245	2.4617
59			8,535					Gas MCF ->	95,393	1,000,000	95,393	252,313	2.9563
60													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 6

Estimated For The Period of : Feb-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	492	318,947	93.1	92.7	98.9	7,169	Gas	MCF ->	2,286,400	1,000,000	2,286,400	6,047,528	1.8961
63	MARTIN 4	492	320,558	93.6	91.6	99.2	7,075	Gas	MCF ->	2,267,959	1,000,000	2,267,959	5,998,752	1.8713
65	FM GT	624	1,129	.3	97.0	90.3	13,209	Light Oil	BBLS ->	2,571	5,799,961	14,909	58,234	5.1594
67	FL GT	768	24	.0	95.0	90.4	19,819	Gas	MCF ->	482	1,000,000	482	1,275	5.2469
69	PE GT	384	39	.0	95.0	95.3	19,462	Gas	MCF ->	762	1,000,000	762	2,017	5.1454
71	SJRPP 1O	119	82,637	100.0	93.3	100.0	9,655	Coal	TONS ->	31,423	25,390,974	797,868	921,959	1.1157
73	SJRPP 2O	118	70,894	86.2	85.5	100.0	9,542	Coal	TONS ->	26,644	25,390,970	676,504	781,719	1.1027
75	SCHER #4	578	383,568	95.3	93.3	95.3	10,270	Coal	TONS ->	225,103	17,499,999	3,939,301	6,451,237	1.6819
77	TOTAL	16,312	4,947,358				9,374					46,375,341	68,061,064	1.3757

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 7

Estimated For The Period of : Mar-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	404	5,312	1.8	86.8	43.7	10,131	Heavy Oil BBLS ->	8,317	6,399,993	53,228	132,649	2.4971
2													
3	TRKY O 2	403	85,537	28.5	92.1	57.8	9,882	Heavy Oil BBLS ->	130,664	6,400,001	836,249	2,084,000	2.4364
4													
5	TRKY N 3	717		.0	85.9		0						
6													
7	TRKY N 4	717	506,727	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,727,536	1,000,000	4,727,536	1,400,296	0.2763
8													
9	FT LAUD4	452	210,285	62.5	91.9	98.5	7,725	Gas MCF ->	1,624,397	1,000,000	1,624,397	4,116,222	1.9575
10													
11	FT LAUD5	452	312,823	93.0	91.9	98.5	7,752	Gas MCF ->	2,425,000	1,000,000	2,425,000	6,144,950	1.9644
12													
13	PT EVER1	212	11	.0	92.9	61.6	10,522	Heavy Oil BBLS ->	18	6,400,000	112	276	2.6038
14													
15	PT EVER2	212	13,981	8.9	92.6	49.3	11,112	Heavy Oil BBLS ->	23,810	6,399,991	152,383	375,158	2.6834
16													
17	PT EVER3	406	142,827	47.3	95.8	69.9	9,921	Heavy Oil BBLS ->	220,478	6,400,001	1,411,058	3,473,957	2.4323
18													
19	PT EVER4	402	126,416	42.3	88.6	67.9	9,878	Heavy Oil BBLS ->	194,089	6,400,001	1,242,169	3,058,159	2.4191
20													
21	RIV 3	282	9,381	4.5	78.3	65.5	10,294	Heavy Oil BBLS ->	14,953	6,400,019	95,701	217,582	2.3195
22													
23	RIV 4	282	126,842	60.5	92.5	74.5	10,152	Heavy Oil BBLS ->	200,469	6,400,001	1,283,000	2,916,972	2.2997
24													
25	ST LUC 1	853	602,816	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,445,699	1,000,000	6,445,699	2,022,660	0.3355
26													
27	ST LUC 2	726	513,017	95.0	85.9	100.0	10,693	Nuclear MBTU ->	5,485,540	1,000,000	5,485,540	1,728,494	0.3369
28													
29	CAP CN 1	391	154,228	53.0	94.4	64.8	9,830	Heavy Oil BBLS ->	236,202	6,400,001	1,511,691	3,632,904	2.3555
30													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 8

Estimated For The Period of : Mar-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	400	35,300	11.9	81.0	59.9	10,026	Heavy Oil BBLS ->	54,992	6,400,000	351,946	845,798	2.3961
33	SANFRD 3	147	803	.7	97.4	46.7	11,790	Heavy Oil BBLS ->	1,402	6,399,971	8,970	20,908	2.6037
35	SANFRD 4	385	170,307	59.5	94.5	68.4	10,336	Heavy Oil BBLS ->	274,656	6,400,001	1,757,800	4,097,167	2.4058
37	SANFRD 5	385	144,948	50.6	94.5	67.1	10,480	Heavy Oil BBLS ->	236,600	6,400,001	1,514,238	3,529,461	2.4350
39	PUTNAM 1	250	163,599	88.0	90.7	94.6	8,179	Gas MCF ->	1,337,426	1,000,000	1,337,426	3,389,038	2.0716
41	PUTNAM 2	250	91,385	49.1	87.8	57.3	8,972	Gas MCF ->	818,288	1,000,000	818,288	2,073,542	2.2690
43	MANATE 1	800	70,236	11.8	94.2	42.3	10,883	Heavy Oil BBLS ->	119,431	6,400,000	764,357	1,863,228	2.6528
45	MANATE 2	799	162,891	27.4	82.8	51.2	10,696	Heavy Oil BBLS ->	272,230	6,400,001	1,742,271	4,247,032	2.6073
47	FT MY 1	142	68,154	64.5	95.8	82.1	10,411	Heavy Oil BBLS ->	110,866	6,400,002	709,542	1,548,777	2.2725
49	FT MY 2	400	242,757	81.6	94.0	86.8	9,533	Heavy Oil BBLS ->	361,598	6,400,000	2,314,227	5,051,456	2.0809
51	CUTLER 5	72	434	.8	97.9	27.6	16,580	Gas MCF ->	6,641	1,000,000	6,641	16,827	3.8736
53	CUTLER 6	145	1,207	1.1	97.3	30.1	13,935	Gas MCF ->	16,178	1,000,000	16,178	40,994	3.3955
55	MARTIN 1	821	35,881	8.4	95.4	51.3	10,566	Heavy Oil BBLS ->	57,742	6,399,998	369,551	872,944	2.4329
56			15,378					Gas MCF ->	166,298	1,000,000	166,298	421,399	2.7403
58	MARTIN 2	830	93,740	21.7	95.7	51.9	10,392	Heavy Oil BBLS ->	148,876	6,400,001	952,808	2,250,700	2.4010
59			40,174					Gas MCF ->	428,763	1,000,000	428,763	1,086,486	2.7044

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 9

Estimated For The Period of : Mar-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	492	344,106	94.0	92.7	99.8	7,161	Gas MCF ->	2,464,092	1,000,000	2,464,092	6,244,008	1.8146
62													
63	MARTIN 4	492	344,903	94.2	91.6	99.9	7,070	Gas MCF ->	2,438,416	1,000,000	2,438,416	6,178,945	1.7915
64													
65	FM GT	624	6,772	1.5	97.0	88.8	13,252	Light Oil BBLS ->	15,472	5,799,991	89,736	335,524	4.9548
66													
67	FL GT	768	270	.0	95.0	79.1	21,261	Gas MCF ->	5,744	1,000,000	5,744	14,554	5.3884
68													
69	PE GT	384	1,227	.4	95.0	79.0	21,307	Gas MCF ->	26,150	1,000,000	26,150	66,263	5.3991
70													
71	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,655	Coal TONS ->	33,575	25,403,017	852,894	986,557	1.1168
72													
73	SJRPP 2O	118	14,179	16.1	85.5	100.0	9,544	Coal TONS ->	5,327	25,402,819	135,326	156,534	1.1040
74													
75	SCHER #4	578	412,620	95.9	93.3	95.9	10,267	Coal TONS ->	242,080	17,500,004	4,236,401	6,936,127	1.6810
76													
77	TOTAL	16,312	5,359,807				9,478				50,801,822	83,578,548	1.5594

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 10

Estimated For The Period of : Apr-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	105,979	36.7	86.8	71.4	10,429	Gas MCF ->	1,099,707	1,000,000	1,099,707	2,794,356	2.6367
2													
3	TRKY O 2	400	9,420	30.9	92.1	68.2	10,398	Heavy Oil BBLS ->	14,515	6,399,989	92,895	234,465	2.4891
4			79,710					Gas MCF ->	825,381	1,000,000	825,381	2,097,292	2.6311
5													
6	TRKY N 3	693	442,368	88.7	85.9	100.0	9,610	Nuclear MBTU ->	4,251,158	1,000,000	4,251,158	1,352,293	0.3057
7													
8	TRKY N 4	693	473,966	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,554,814	1,000,000	4,554,814	1,328,639	0.2803
9													
10	FT LAUD4	430	291,606	94.2	91.9	99.7	7,783	Gas MCF ->	2,269,606	1,000,000	2,269,606	5,767,067	1.9777
11													
12	FT LAUD5	430	291,483	94.1	91.9	99.7	7,811	Gas MCF ->	2,276,791	1,000,000	2,276,791	5,785,325	1.9848
13													
14	PT EVER1	211	712	.5	92.9	56.0	11,264	Heavy Oil BBLS ->	1,229	6,400,114	7,865	20,470	2.8754
15													
16	PT EVER2	211	16,831	11.1	92.6	45.2	11,342	Heavy Oil BBLS ->	29,267	6,400,008	187,310	487,511	2.8965
17													
18	PT EVER3	403	192,188	66.2	95.8	83.4	9,839	Heavy Oil BBLS ->	294,633	6,400,000	1,885,648	4,907,762	2.5536
19													
20	PT EVER4	402	172,082	59.5	88.6	81.8	9,838	Heavy Oil BBLS ->	263,569	6,400,000	1,686,842	4,390,330	2.5513
21													
22	RIV 3	280		.0	78.3		0						
23													
24	RIV 4	280	97,720	48.5	92.5	79.3	10,270	Heavy Oil BBLS ->	155,795	6,400,002	997,090	2,337,980	2.3925
25													
26	ST LUC 1	839	573,794	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,211,379	1,000,000	6,211,379	1,921,801	0.3349
27													
28	ST LUC 2	714	260,436	50.7	85.9	100.0	10,825	Nuclear MBTU ->	2,819,244	1,000,000	2,819,244	875,375	0.3361
29													
30	CAP CN 1	388	196,640	70.4	94.4	81.1	9,837	Heavy Oil BBLS ->	301,842	6,400,000	1,931,788	4,816,735	2.4495
31													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 11

Estimated For The Period of : Apr-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	CAP CN 2	397		.0	81.0		0						
34	SANFRD 3	142		.0	97.4		0						
36	SANFRD 4	383	145,245	52.7	94.5	80.4	10,418	Heavy Oil BBLS ->	235,573	6,400,002	1,507,669	3,707,893	2.5528
38	SANFRD 5	383	128,775	46.7	94.5	78.1	10,546	Heavy Oil BBLS ->	211,316	6,399,999	1,352,421	3,326,083	2.5829
40	PUTNAM 1	245	153,835	87.2	90.7	98.0	8,226	Gas MCF ->	1,264,156	1,000,000	1,264,156	3,212,220	2.0881
42	PUTNAM 2	245	60,095	34.1	87.8	45.6	9,608	Gas MCF ->	574,621	1,000,000	574,621	1,460,113	2.4297
44	MANATE 1	798	44,324	7.7	94.2	54.5	10,830	Heavy Oil BBLS ->	75,002	6,400,000	480,011	1,203,981	2.7163
46	MANATE 2	792	167,786	29.4	82.8	60.1	10,723	Heavy Oil BBLS ->	281,119	6,399,999	1,799,164	4,512,727	2.6896
48	FT MY 1	141	59,322	58.4	95.8	89.7	10,501	Heavy Oil BBLS ->	97,338	6,400,001	622,963	1,446,668	2.4387
50	FT MY 2	397	239,083	83.6	94.0	93.1	9,559	Heavy Oil BBLS ->	357,086	6,400,000	2,285,350	5,307,127	2.2198
52	CUTLER 5	71	4	.0	97.9	82.6	13,289	Gas MCF ->	56	1,000,000	56	143	3.4048
54	CUTLER 6	144	13	.0	97.3	71.6	12,270	Gas MCF ->	164	1,000,000	164	417	3.1119
56	MARTIN 1	814	862	3.4	95.4	60.6	10,893	Heavy Oil BBLS ->	1,386	6,399,870	8,868	21,016	2.4392
57			19,130					Gas MCF ->	206,754	1,000,000	206,754	525,362	2.7462
59	MARTIN 2	813	5,766	17.5	95.7	59.8	10,828	Heavy Oil BBLS ->	9,252	6,400,004	59,212	140,317	2.4335
60			96,447					Gas MCF ->	1,039,934	1,000,000	1,039,934	2,642,471	2.7398

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 12

Estimated For The Period of : Apr-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 3	465	283,163	84.6	92.7	90.1	7,351	Gas MCF ->	2,081,578	1,000,000	2,081,578	5,289,290	1.8679
64	MARTIN 4	465	230,572	68.9	91.6	73.4	7,443	Gas MCF ->	1,716,163	1,000,000	1,716,163	4,360,771	1.8913
66	FM GT	552	10	.0	97.0	86.4	13,702	Light Oil BBLS ->	24	5,804,167	139	537	5.2647
68	FL GT	684	1	.0	95.0		0	Gas MCF ->	8	1,000,000	8	19	3.8000
70	PE GT	336	0	.0	95.0		0	Gas MCF ->	0	1,000,000	0	0	
72	SJRPP 1O	119	85,487	100.0	93.3	100.0	9,752	Coal TONS ->	32,805	25,414,024	833,697	965,769	1.1297
74	SJRPP 2O	118	85,073	100.0	85.5	100.0	9,637	Coal TONS ->	32,261	25,413,968	819,885	949,770	1.1164
76	SCHER #4	578	411,167	98.7	93.3	98.7	10,359	Coal TONS ->	243,380	17,500,000	4,259,154	6,972,698	1.6958
78	TOTAL	15,857	5,421,097				9,594				52,009,482	85,162,793	1.5710

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 13

Estimated For The Period of : May-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	140,196	47.0	86.8	76.3	9,865	Heavy Oil BBLS ->	215,143	6,400,000	1,376,917	3,569,747	2.5463
2													
3	TRKY O 2	400	113,866	38.3	92.1	73.8	9,876	Heavy Oil BBLS ->	174,386	6,399,999	1,116,069	2,893,481	2.5411
4													
5	TRKY N 3	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,498,124	0.3059
6													
7	TRKY N 4	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,373,398	0.2804
8													
9	FT LAUD4	430	302,034	94.4	91.9	100.0	7,781	Gas MCF ->	2,350,140	1,000,000	2,350,140	6,096,263	2.0184
10													
11	FT LAUD5	430	302,055	94.4	91.9	99.9	7,808	Gas MCF ->	2,358,569	1,000,000	2,358,569	6,118,127	2.0255
12													
13	PT EVER1	211	7,092	4.5	92.9	63.1	11,088	Heavy Oil BBLS ->	12,094	6,400,020	77,404	202,875	2.8606
14													
15	PT EVER2	211	31,258	19.9	92.6	56.9	10,961	Heavy Oil BBLS ->	52,851	6,399,997	338,246	886,533	2.8362
16													
17	PT EVER3	403	237,817	79.3	95.8	90.5	9,759	Heavy Oil BBLS ->	362,145	6,400,000	2,317,729	6,074,710	2.5544
18													
19	PT EVER4	402	218,315	73.0	88.6	88.9	9,788	Heavy Oil BBLS ->	333,203	6,400,000	2,132,499	5,589,225	2.5602
20													
21	RIV 3	280	103,314	49.6	78.3	90.5	10,187	Heavy Oil BBLS ->	163,546	6,399,998	1,046,695	2,515,254	2.4346
22													
23	RIV 4	280	131,869	63.3	92.5	90.2	10,169	Heavy Oil BBLS ->	208,537	6,399,999	1,334,637	3,207,191	2.4321
24													
25	ST LUC 1	839	592,920	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,418,426	1,000,000	6,418,426	1,981,368	0.3342
26													
27	ST LUC 2	714	162,772	30.6	85.9	100.0	10,825	Nuclear MBTU ->	1,762,025	1,000,000	1,762,025	550,633	0.3383
28													
29	CAP CN 1	388	230,707	79.9	94.4	88.4	9,779	Heavy Oil BBLS ->	352,253	6,400,001	2,254,422	5,724,773	2.4814
30													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 14

Estimated For The Period of : May-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	403	145,802	48.6	81.0	86.7	9,897	Heavy Oil BBLS ->	224,754	6,400,001	1,438,427	3,652,674	2.5052
33	SANFRD 3	142	3,837	3.6	97.4	62.1	11,359	Heavy Oil BBLS ->	6,596	6,399,967	42,216	105,589	2.7519
35	SANFRD 4	383	179,544	63.0	94.5	91.6	10,308	Heavy Oil BBLS ->	288,317	6,400,001	1,845,231	4,615,192	2.5705
37	SANFRD 5	383	153,184	53.8	94.5	84.0	10,472	Heavy Oil BBLS ->	249,788	6,399,999	1,598,644	3,998,442	2.6102
39	PUTNAM 1	245	171,242	93.9	90.7	99.4	8,204	Gas MCF ->	1,404,640	1,000,000	1,404,640	3,643,637	2.1278
41	PUTNAM 2	245	155,983	85.6	87.8	98.6	8,212	Gas MCF ->	1,279,393	1,000,000	1,279,393	3,318,744	2.1276
43	MANATE 1	798	107,666	18.1	94.2	58.4	10,758	Heavy Oil BBLS ->	180,987	6,400,001	1,158,316	2,961,126	2.7503
45	MANATE 2	792	219,628	37.3	82.8	66.3	10,631	Heavy Oil BBLS ->	364,807	6,400,000	2,334,765	5,968,607	2.7176
47	FT MY 1	141	66,731	63.6	95.8	92.3	10,480	Heavy Oil BBLS ->	109,273	6,399,997	699,348	1,649,889	2.4724
49	FT MY 2	397	262,760	89.0	94.0	95.5	9,541	Heavy Oil BBLS ->	391,717	6,400,000	2,506,989	5,914,441	2.2509
51	CUTLER 5	71	502	1.0	97.9	29.9	16,174	Gas MCF ->	7,723	1,000,000	7,723	20,034	3.9885
53	CUTLER 6	144	2,197	2.1	97.3	46.7	13,060	Gas MCF ->	28,050	1,000,000	28,050	72,762	3.3116
55	MARTIN 1	814	44,481	10.5	95.4	60.7	10,540	Heavy Oil BBLS ->	71,553	6,400,004	457,938	1,135,388	2.5525
56			19,063					Gas MCF ->	206,072	1,000,000	206,072	534,550	2.8041
58	MARTIN 2	813	117,611	27.8	95.7	65.4	10,409	Heavy Oil BBLS ->	187,407	6,400,000	1,199,404	2,973,744	2.5285
59			50,405					Gas MCF ->	539,732	1,000,000	539,732	1,400,066	2.7777

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 15

Estimated For The Period of : May-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	465	325,932	94.2	92.7	100.0	7,273	Gas MCF ->	2,370,407	1,000,000	2,370,407	6,148,834	1.8865
63	MARTIN 4	465	300,045	86.7	91.6	91.9	7,252	Gas MCF ->	2,175,895	1,000,000	2,175,895	5,644,271	1.8811
65	FM GT	552	6,651	1.6	97.0	99.5	13,702	Light Oil BBLS ->	15,712	5,799,991	91,131	346,299	5.2068
67	FL GT	684	1,378	.3	95.0	87.8	15,628	Gas MCF ->	21,542	1,000,000	21,542	55,880	4.0540
69	PE GT	336	6	.0	95.0	90.4	17,514	Gas MCF ->	99	1,000,000	99	257	4.5088
71	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,752	Coal TONS ->	33,883	25,425,028	861,486	999,394	1.1314
73	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,637	Coal TONS ->	33,322	25,425,009	847,215	982,838	1.1180
75	SCHER #4	578	429,596	99.8	93.3	99.8	10,355	Coal TONS ->	254,202	17,500,002	4,448,539	7,279,759	1.6946
77	TOTAL	15,863	6,494,234				9,525				61,860,264	111,704,119	1.7201

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 16

Estimated For The Period of : Jun-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	157,810	54.7	86.8	92.2	10,291	Gas MCF ->	1,618,086	1,000,000	1,618,086	4,119,648	2.6105
2													
3	TRKY O 2	400	43,420	46.3	92.1	89.7	10,153	Heavy Oil BBLS ->	66,229	6,399,998	423,862	1,104,035	2.5427
4			89,894					Gas MCF ->	921,424	1,000,000	921,424	2,345,946	2.6097
5													
6	TRKY N 3	693	473,966	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,554,814	1,000,000	4,554,814	1,450,708	0.3061
7													
8	TRKY N 4	693	473,966	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,554,814	1,000,000	4,554,814	1,330,006	0.2806
9													
10	FT LAUD4	430	292,397	94.4	91.9	100.0	7,781	Gas MCF ->	2,275,068	1,000,000	2,275,068	5,792,322	1.9810
11													
12	FT LAUD5	430	292,459	94.5	91.9	100.0	7,808	Gas MCF ->	2,283,523	1,000,000	2,283,523	5,813,850	1.9879
13													
14	PT EVER1	211	16,590	10.9	92.9	91.1	10,755	Heavy Oil BBLS ->	27,592	6,399,995	176,589	465,385	2.8052
15													
16	PT EVER2	211	55,594	36.6	92.6	88.5	10,505	Heavy Oil BBLS ->	90,548	6,399,996	579,506	1,527,234	2.7471
17													
18	PT EVER3	403	212,099	73.1	95.8	94.0	9,742	Heavy Oil BBLS ->	322,010	6,400,000	2,060,866	5,431,226	2.5607
19													
20	PT EVER4	402	188,710	65.2	88.6	94.9	9,773	Heavy Oil BBLS ->	287,205	6,400,001	1,838,113	4,844,180	2.5670
21													
22	RIV 3	280	137,814	68.4	78.3	92.6	10,161	Heavy Oil BBLS ->	217,896	6,400,000	1,394,536	3,370,591	2.4458
23													
24	RIV 4	280	156,593	77.7	92.5	93.7	10,131	Heavy Oil BBLS ->	247,239	6,400,000	1,582,327	3,824,483	2.4423
25													
26	ST LUC 1	839	573,794	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,211,379	1,000,000	6,211,379	1,919,937	0.3346
27													
28	ST LUC 2	714	488,319	95.0	85.9	100.0	10,825	Nuclear MBTU ->	5,286,087	1,000,000	5,286,087	1,656,131	0.3391
29													
30	CAP CN 1	388	236,803	84.8	94.4	91.2	9,761	Heavy Oil BBLS ->	361,069	6,400,000	2,310,839	5,903,483	2.4930
31													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 17

Estimated For The Period of : Jun-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	CAP CN 2	403	193,893	66.8	81.0	94.3	9,873	Heavy Oil BBLS ->	298,200	6,400,000	1,908,481	4,875,581	2.5146
33													
34	SANFRD 3	142	41,907	41.0	97.4	90.0	10,975	Heavy Oil BBLS ->	71,203	6,400,000	455,699	1,140,632	2.7218
35													
36	SANFRD 4	383	216,048	78.3	94.5	92.5	10,294	Heavy Oil BBLS ->	346,992	6,400,000	2,220,750	5,558,620	2.5729
37													
38	SANFRD 5	383	165,560	60.0	94.5	95.2	10,431	Heavy Oil BBLS ->	268,987	6,400,000	1,721,518	4,309,024	2.6027
39													
40	PUTNAM 1	245	164,772	93.4	90.7	99.7	8,200	Gas MCF ->	1,350,811	1,000,000	1,350,811	3,439,164	2.0872
41													
42	PUTNAM 2	245	154,545	87.6	87.8	99.1	8,201	Gas MCF ->	1,266,491	1,000,000	1,266,491	3,224,485	2.0864
43													
44	MANATE 1	798	150,163	26.1	94.2	69.7	10,683	Heavy Oil BBLS ->	250,651	6,400,001	1,604,166	4,158,779	2.7695
45													
46	MANATE 2	792	279,620	49.0	82.8	85.1	10,560	Heavy Oil BBLS ->	461,354	6,400,001	2,952,668	7,654,754	2.7376
47													
48	FT MY 1	141	68,772	67.7	95.8	92.9	10,475	Heavy Oil BBLS ->	112,556	6,400,001	720,359	1,700,479	2.4726
49													
50	FT MY 2	397	264,472	92.5	94.0	98.5	9,525	Heavy Oil BBLS ->	393,609	6,400,000	2,519,095	5,946,574	2.2485
51													
52	CUTLER 5	71	1,842	3.6	97.9	51.2	14,219	Gas MCF ->	25,470	1,000,000	25,470	64,846	3.5202
53													
54	CUTLER 6	144	5,556	5.4	97.3	62.7	12,635	Gas MCF ->	69,180	1,000,000	69,180	176,132	3.1703
55													
56	MARTIN 1	814	8,643	17.0	95.4	68.8	10,765	Heavy Oil BBLS ->	13,804	6,400,001	88,347	221,471	2.5626
57			91,200					Gas MCF ->	978,882	1,000,000	978,882	2,492,233	2.7327
58													
59	MARTIN 2	813	34,823	36.9	95.7	77.3	10,619	Heavy Oil BBLS ->	55,198	6,400,003	353,265	885,577	2.5431
60			181,135					Gas MCF ->	1,929,441	1,000,000	1,929,441	4,912,355	2.7120
61													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 18

Estimated For The Period of : Jun-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 3	465	315,418	94.2	92.7	100.0	7,273	Gas MCF ->	2,293,939	1,000,000	2,293,939	5,840,369	1.8516
64	MARTIN 4	465	315,837	94.3	91.6	100.0	7,191	Gas MCF ->	2,271,051	1,000,000	2,271,051	5,782,095	1.8307
66	FM GT	552	18,917	4.8	97.0	99.4	13,702	Light Oil BBLS ->	44,689	5,800,001	259,198	934,150	4.9382
68	FL GT	684	31	1.3	95.0	88.6	15,607	Light Oil BBLS ->	80	5,830,189	464	1,980	6.3462
69			6,223					Gas MCF ->	97,150	1,000,000	97,150	247,344	3.9744
71	PE GT	336	190	.1	95.0	92.0	17,693	Gas MCF ->	3,365	1,000,000	3,365	8,566	4.5037
73	SJRPP 1O	119	85,487	100.0	93.3	100.0	9,752	Coal TONS ->	32,775	25,436,976	833,697	968,479	1.1329
75	SJRPP 2O	118	85,073	100.0	85.5	100.0	9,637	Coal TONS ->	32,232	25,436,991	819,885	952,434	1.1195
77	SCHER #4	578	416,400	100.0	93.3	100.0	10,355	Coal TONS ->	246,390	17,500,001	4,311,827	7,054,880	1.6943
79	TOTAL	15,863	7,156,752				9,659				69,127,030	123,450,168	1.7249

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 19

Estimated For The Period of : Jul-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	176,945	59.3	86.8	94.2	9,796	Heavy Oil BBLS ->	269,872	6,400,000	1,727,183	4,580,769	2.5888
3	TRKY O 2	400	152,001	51.1	92.1	92.0	9,817	Heavy Oil BBLS ->	231,843	6,400,001	1,483,796	3,935,265	2.5890
5	TRKY N 3	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,477,415	0.3017
7	TRKY N 4	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,353,160	0.2763
9	FT LAUD4	430	302,150	94.4	91.9	100.0	7,781	Gas MCF ->	2,350,951	1,000,000	2,350,951	6,197,107	2.0510
11	FT LAUD5	430	302,220	94.5	91.9	100.0	7,808	Gas MCF ->	2,359,725	1,000,000	2,359,725	6,220,234	2.0582
13	PT EVER1	211	37,764	24.1	92.9	93.4	10,714	Heavy Oil BBLS ->	62,667	6,400,000	401,070	1,062,932	2.8147
15	PT EVER2	211	67,738	43.1	92.6	92.5	10,468	Heavy Oil BBLS ->	110,037	6,400,002	704,235	1,866,391	2.7553
17	PT EVER3	403	232,606	77.6	95.8	96.2	9,722	Heavy Oil BBLS ->	352,566	6,400,000	2,256,420	5,980,052	2.5709
19	PT EVER4	402	198,590	66.4	88.6	96.2	9,770	Heavy Oil BBLS ->	302,162	6,400,001	1,933,836	5,125,128	2.5808
21	RIV 3	280	141,242	67.8	78.3	95.0	10,139	Heavy Oil BBLS ->	222,808	6,400,001	1,425,973	3,445,698	2.4396
23	RIV 4	280	162,956	78.2	92.5	96.5	10,111	Heavy Oil BBLS ->	256,760	6,400,001	1,643,264	3,970,756	2.4367
25	ST LUC 1	839	592,920	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,418,426	1,000,000	6,418,426	1,947,992	0.3285
27	ST LUC 2	714	504,597	95.0	85.9	100.0	10,825	Nuclear MBTU ->	5,462,290	1,000,000	5,462,290	1,697,133	0.3363
29	CAP CN 1	388	248,918	86.2	94.4	94.3	9,745	Heavy Oil BBLS ->	378,866	6,400,000	2,424,739	6,214,113	2.4965

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 20

Estimated For The Period of : Jul-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned *Fuel Cost* ($)	(M) Fuel Cost *per* KWH (C/KWH)
31	CAP CN 2	403	254,822	85.0	81.0	93.3	9,858	Heavy Oil BBLS ->	392,303	6,400,000	2,510,737	6,434,508	2.5251
32													
33	SANFRD 3	142	48,354	45.8	97.4	92.9	10,971	Heavy Oil BBLS ->	82,110	6,400,004	525,506	1,312,051	2.7135
34													
35	SANFRD 4	383	250,991	88.1	94.5	96.3	10,258	Heavy Oil BBLS ->	402,070	6,400,000	2,573,248	6,424,731	2.5597
36													
37	SANFRD 5	383	197,045	69.2	94.5	96.3	10,424	Heavy Oil BBLS ->	320,065	6,400,001	2,048,416	5,114,363	2.5955
38													
39	PUTNAM 1	245	172,869	94.8	90.7	100.0	8,198	Gas MCF ->	1,417,008	1,000,000	1,417,008	3,735,234	2.1607
40													
41	PUTNAM 2	245	166,262	91.2	87.8	99.6	8,199	Gas MCF ->	1,362,343	1,000,000	1,362,343	3,591,137	2.1599
42													
43	MANATE 1	798	216,941	36.5	94.2	78.0	10,674	Heavy Oil BBLS ->	361,813	6,400,001	2,315,603	6,062,276	2.7944
44													
45	MANATE 2	792	344,021	58.4	82.8	89.0	10,546	Heavy Oil BBLS ->	566,900	6,400,000	3,628,160	9,498,568	2.7610
46													
47	FT MY 1	141	74,209	70.7	95.8	95.8	10,450	Heavy Oil BBLS ->	121,175	6,399,998	775,517	1,826,729	2.4616
48													
49	FT MY 2	397	276,737	93.7	94.0	99.7	9,519	Heavy Oil BBLS ->	411,592	6,399,999	2,634,187	6,204,827	2.2421
50													
51	CUTLER 5	71	6,321	12.0	97.9	61.6	13,900	Gas MCF ->	86,337	1,000,000	86,337	227,585	3.6005
52													
53	CUTLER 6	144	16,355	15.3	97.3	70.1	12,519	Gas MCF ->	202,804	1,000,000	202,804	534,592	3.2687
54													
55	MARTIN 1	814	115,645	27.3	95.4	74.4	10,430	Heavy Oil BBLS ->	184,634	6,399,999	1,181,655	3,087,574	2.6699
56			49,562					Gas MCF ->	531,745	1,000,000	531,745	1,401,679	2.8281
57													
58	MARTIN 2	813	202,022	47.7	95.7	85.5	10,334	Heavy Oil BBLS ->	320,181	6,400,000	2,049,156	5,354,289	2.6503
59			86,581					Gas MCF ->	922,120	1,000,000	922,120	2,430,709	2.8074
60													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 21

Estimated For The Period of : Jul-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	465	325,932	94.2	92.7	100.0	7,273	Gas	MCF ->	2,370,407	1,000,000	2,370,407	6,248,392	1.9171
63	MARTIN 4	465	326,365	94.3	91.6	100.0	7,191	Gas	MCF ->	2,346,755	1,000,000	2,346,755	6,186,047	1.8954
65	FM GT	552	46,402	11.3	97.0	99.4	13,702	Light Oil	BBLS ->	109,620	5,800,003	635,794	2,285,679	4.9259
67	FL GT	684	2,947	4.0	95.0	88.5	15,506	Light Oil	BBLS ->	7,517	5,829,966	43,826	186,328	6.3224
68			17,297					Gas	MCF ->	270,090	1,000,000	270,090	711,957	4.1160
70	PE GT	336	3,361	1.3	95.0	88.6	18,130	Gas	MCF ->	60,934	1,000,000	60,934	160,621	4.7791
72	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,752	Coal	TONS ->	33,825	25,469,001	861,486	1,002,014	1.1343
74	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,637	Coal	TONS ->	33,265	25,469,035	847,215	985,414	1.1210
76	SCHER #4	578	430,328	100.0	93.3	100.0	10,355	Coal	TONS ->	254,631	17,499,997	4,456,047	7,298,194	1.6960
78	TOTAL	15,863	7,907,788				9,695					76,662,285	143,379,643	1.8131

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 22

Estimated For The Period of : Aug-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	179,581	60.2	86.8	93.4	9,794	Heavy Oil BBLS ->	273,861	6,399,999	1,752,707	4,520,993	2.5175
3	TRKY O 2	400	153,990	51.7	92.1	92.4	9,811	Heavy Oil BBLS ->	234,734	6,400,001	1,502,298	3,875,079	2.5164
5	TRKY N 3	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,478,356	0.3018
7	TRKY N 4	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,353,630	0.2764
9	FT LAUD4	430	302,150	94.4	91.9	100.0	7,781	Gas MCF ->	2,350,951	1,000,000	2,350,951	5,698,705	1.8861
11	FT LAUD5	430	302,220	94.5	91.9	100.0	7,808	Gas MCF ->	2,359,725	1,000,000	2,359,725	5,719,972	1.8927
13	PT EVER1	211	42,889	27.3	92.9	92.0	10,711	Heavy Oil BBLS ->	71,224	6,400,002	455,835	1,156,312	2.6960
15	PT EVER2	211	72,517	46.2	92.6	92.5	10,467	Heavy Oil BBLS ->	117,837	6,399,999	754,158	1,913,065	2.6381
17	PT EVER3	403	274,013	91.4	95.8	95.4	9,711	Heavy Oil BBLS ->	415,764	6,400,001	2,660,889	6,749,850	2.4633
19	PT EVER4	402	260,520	87.1	88.6	93.1	9,755	Heavy Oil BBLS ->	396,875	6,400,000	2,540,003	6,443,199	2.4732
21	RIV 3	280	135,606	65.1	78.3	94.2	10,153	Heavy Oil BBLS ->	214,082	6,400,001	1,370,125	3,225,321	2.3785
23	RIV 4	280	153,165	73.5	92.5	93.5	10,137	Heavy Oil BBLS ->	241,767	6,400,001	1,547,309	3,642,418	2.3781
25	ST LUC 1	839	592,920	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,418,426	1,000,000	6,418,426	1,944,783	0.3280
27	ST LUC 2	714	504,597	95.0	85.9	100.0	10,825	Nuclear MBTU ->	5,462,290	1,000,000	5,462,290	1,698,772	0.3367
29	CAP CN 1	388	256,127	88.7	94.4	94.6	9,737	Heavy Oil BBLS ->	389,655	6,400,000	2,493,792	6,166,597	2.4076

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 23

Estimated For The Period of : Aug-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	403	240,016	80.1	81.0	92.3	9,864	Heavy Oil BBLS ->	369,441	6,400,000	2,364,421	5,846,690	2.4360
33	SANFRD 3	142	42,247	40.0	97.4	89.1	10,969	Heavy Oil BBLS ->	71,747	6,400,004	459,179	1,114,029	2.6369
35	SANFRD 4	383	205,614	72.2	94.5	95.8	10,276	Heavy Oil BBLS ->	329,342	6,400,001	2,107,789	5,113,779	2.4871
37	SANFRD 5	383	186,074	65.3	94.5	95.4	10,427	Heavy Oil BBLS ->	302,264	6,400,000	1,934,490	4,693,331	2.5223
39	PUTNAM 1	245	172,434	94.6	90.7	99.9	8,198	Gas MCF ->	1,413,450	1,000,000	1,413,450	3,426,202	1.9870
41	PUTNAM 2	245	166,168	91.2	87.8	99.7	8,199	Gas MCF ->	1,361,574	1,000,000	1,361,574	3,300,455	1.9862
43	MANATE 1	798	209,031	35.2	94.2	77.1	10,666	Heavy Oil BBLS ->	348,356	6,400,000	2,229,477	5,657,441	2.7065
45	MANATE 2	792	327,025	55.5	82.8	89.4	10,540	Heavy Oil BBLS ->	538,567	6,400,000	3,446,831	8,746,554	2.6746
47	FT MY 1	141	72,968	69.6	95.8	95.0	10,449	Heavy Oil BBLS ->	119,130	6,400,005	762,431	1,753,965	2.4037
49	FT MY 2	397	276,767	93.7	94.0	99.7	9,518	Heavy Oil BBLS ->	411,611	6,400,000	2,634,312	6,060,211	2.1896
51	CUTLER 5	71	6,955	13.2	97.9	55.9	14,073	Gas MCF ->	96,191	1,000,000	96,191	233,167	3.3526
53	CUTLER 6	144	17,967	16.8	97.3	68.0	12,536	Gas MCF ->	223,288	1,000,000	223,288	541,249	3.0125
55	MARTIN 1	814	117,638	27.7	95.4	75.3	10,429	Heavy Oil BBLS ->	187,815	6,400,000	1,202,017	3,099,502	2.6348
56			50,416					Gas MCF ->	540,908	1,000,000	540,908	1,311,160	2.6007
58	MARTIN 2	813	194,784	46.0	95.7	84.8	10,334	Heavy Oil BBLS ->	308,646	6,400,000	1,975,333	5,093,563	2.6150
59			83,479					Gas MCF ->	888,901	1,000,000	888,901	2,154,696	2.5811

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 24

Estimated For The Period of : Aug-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	465	325,932	94.2	92.7	100.0	7,273	Gas MCF ->	2,370,407	1,000,000	2,370,407	5,745,865	1.7629
62													
63	MARTIN 4	465	326,365	94.3	91.6	100.0	7,191	Gas MCF ->	2,346,755	1,000,000	2,346,755	5,688,535	1.7430
64													
65	FM GT	552	68,901	16.8	97.0	99.6	13,702	Light Oil BBLS ->	162,773	5,799,999	944,085	3,447,798	5.0040
66													
67	FL GT	684	11,792	8.5	95.0	88.4	15,421	Light Oil BBLS ->	30,095	5,829,997	175,452	649,699	5.5099
68			31,561					Gas MCF ->	493,088	1,000,000	493,088	1,195,244	3.7871
69													
70	PE GT	336	12,257	4.8	95.0	88.2	18,178	Gas MCF ->	222,820	1,000,000	222,820	540,115	4.4064
71													
72	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,752	Coal TONS ->	33,783	25,500,966	861,486	1,003,338	1.1358
73													
74	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,637	Coal TONS ->	33,223	25,500,999	847,215	986,716	1.1224
75													
76	SCHER #4	578	430,328	100.0	93.3	100.0	10,355	Coal TONS ->	254,631	17,499,997	4,456,047	7,306,451	1.6979
77													
78	TOTAL	15,863	7,962,788				9,725				77,439,734	140,296,807	1.7619

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 25

Estimated For The Period of : Sep-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	2,936	59.6	86.8	92.0	10,277	Heavy Oil BBLS ->	4,479	6,400,067	28,666	73,563	2.5054
2			169,246					Gas MCF ->	1,734,929	1,000,000	1,734,929	4,054,530	2.3956
4	TRKY O 2	400	61,342	52.0	92.1	91.2	10,099	Heavy Oil BBLS ->	93,516	6,400,001	598,504	1,535,891	2.5038
5			88,301					Gas MCF ->	904,612	1,000,000	904,612	2,114,078	2.3942
7	TRKY N 3	693	473,966	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,554,814	1,000,000	4,554,814	1,431,578	0.3020
9	TRKY N 4	693	473,966	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,554,814	1,000,000	4,554,814	1,310,420	0.2765
11	FT LAUD4	430	292,327	94.4	91.9	100.0	7,781	Gas MCF ->	2,274,601	1,000,000	2,274,601	5,315,742	1.8184
13	FT LAUD5	430	282,616	91.3	91.9	100.0	7,808	Gas MCF ->	2,206,763	1,000,000	2,206,763	5,157,204	1.8248
15	PT EVER1	211	9,557	15.6	92.9	92.2	11,050	Heavy Oil BBLS ->	15,871	6,399,996	101,577	254,418	2.6623
16			14,103					Gas MCF ->	157,403	1,000,000	157,403	367,850	2.6082
18	PT EVER2	211	19,631	39.7	92.6	91.2	10,830	Heavy Oil BBLS ->	31,913	6,399,991	204,240	511,556	2.6058
19			40,754					Gas MCF ->	445,200	1,000,000	445,200	1,040,433	2.5529
21	PT EVER3	403	238,724	91.8	95.8	96.5	9,754	Heavy Oil BBLS ->	361,926	6,400,001	2,316,328	5,801,674	2.4303
22			27,788					Gas MCF ->	283,101	1,000,000	283,101	661,607	2.3810
24	PT EVER4	402	147,928	87.2	88.6	93.0	9,958	Heavy Oil BBLS ->	225,395	6,400,001	1,442,529	3,613,082	2.4425
25			104,551					Gas MCF ->	1,070,513	1,000,000	1,070,513	2,501,789	2.3929
27	RIV 3	280	123,177	61.1	78.3	94.0	10,155	Heavy Oil BBLS ->	194,438	6,399,999	1,244,405	2,927,921	2.3770
29	RIV 4	280	132,069	65.5	92.5	94.2	10,138	Heavy Oil BBLS ->	208,250	6,400,000	1,332,800	3,135,903	2.3745

Date: 9/3/99

Company: Florida Power & Light

Schedule E4

Page: 26

Estimated For The Period of : Sep-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	839	573,794	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,211,379	1,000,000	6,211,379	1,878,942	0.3275
33	ST LUC 2	714	488,319	95.0	85.9	100.0	10,825	Nuclear MBTU ->	5,286,087	1,000,000	5,286,087	1,645,030	0.3369
35	CAP CN 1	388	231,137	82.7	94.4	93.9	9,751	Heavy Oil BBLS ->	351,763	6,400,000	2,251,283	5,517,924	2.3873
37	CAP CN 2	403	220,989	76.2	81.0	92.4	9,864	Heavy Oil BBLS ->	339,985	6,400,001	2,175,906	5,333,174	2.4133
39	SANFRD 3	142	12,672	12.4	97.4	78.3	10,996	Heavy Oil BBLS ->	21,461	6,399,996	137,352	333,631	2.6328
41	SANFRD 4	383	174,633	63.3	94.5	94.7	10,284	Heavy Oil BBLS ->	279,755	6,400,000	1,790,429	4,349,007	2.4904
43	SANFRD 5	383	131,487	47.7	94.5	91.6	10,442	Heavy Oil BBLS ->	213,679	6,399,999	1,367,542	3,321,803	2.5263
45	PUTNAM 1	245	164,008	93.0	90.7	99.7	8,202	Gas MCF ->	1,344,664	1,000,000	1,344,664	3,142,480	1.9161
47	PUTNAM 2	245	151,737	86.0	87.8	99.0	8,205	Gas MCF ->	1,243,614	1,000,000	1,243,614	2,906,325	1.9154
49	MANATE 1	798	146,802	25.6	94.2	68.7	10,673	Heavy Oil BBLS ->	244,819	6,400,000	1,566,838	3,925,734	2.6742
51	MANATE 2	792	296,647	52.0	82.8	85.6	10,543	Heavy Oil BBLS ->	488,689	6,399,999	3,127,606	7,836,258	2.6416
53	FT MY 1	141	68,515	67.5	95.8	94.4	10,453	Heavy Oil BBLS ->	111,909	6,399,998	716,215	1,642,643	2.3975
55	FT MY 2	397	265,826	93.0	94.0	99.4	9,521	Heavy Oil BBLS ->	395,450	6,400,001	2,530,882	5,804,593	2.1836
57	CUTLER 5	71	2,637	5.2	97.9	49.2	14,305	Gas MCF ->	36,686	1,000,000	36,686	85,736	3.2508
59	CUTLER 6	144	7,645	7.4	97.3	61.4	12,637	Gas MCF ->	95,318	1,000,000	95,318	222,758	2.9137

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 28

Estimated For The Period of : Oct-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	401	85,439	42.7	86.8	73.7	10,074	Heavy Oil BBLS ->	131,675	6,400,001	842,719	2,231,734	2.6121
2			41,995					Gas MCF ->	434,927	1,000,000	434,927	1,126,026	2.6813
3													
4	TRKY O 2	400	94,495	35.9	92.1	73.0	9,962	Heavy Oil BBLS ->	145,092	6,400,002	928,591	2,459,145	2.6024
5			12,245					Gas MCF ->	126,347	1,000,000	126,347	327,111	2.6714
6													
7	TRKY N 3	693	489,765	95.0	85.9	100.0	9,610	Nuclear MBTU ->	4,706,642	1,000,000	4,706,642	1,456,706	0.2974
8													
9	TRKY N 4	693	15,799	3.1	85.9	100.0	9,610	Nuclear MBTU ->	151,827	1,000,000	151,827	43,058	0.2725
10													
11	FT LAUD4	430	302,049	94.4	91.9	100.0	7,781	Gas MCF ->	2,350,245	1,000,000	2,350,245	6,084,783	2.0145
12													
13	FT LAUD5	430	212,543	66.4	91.9	99.9	7,809	Gas MCF ->	1,659,643	1,000,000	1,659,643	4,296,816	2.0216
14													
15	PT EVER1	211	9,715	6.2	92.9	32.9	12,281	Heavy Oil BBLS ->	18,209	6,399,990	116,536	305,278	3.1424
16			1					Gas MCF ->	17	1,000,000	17	44	3.1429
17													
18	PT EVER2	211	30,758	21.6	92.6	50.3	11,168	Heavy Oil BBLS ->	52,762	6,400,005	337,680	884,589	2.8760
19			3,180					Gas MCF ->	36,656	1,000,000	36,656	94,902	2.9844
20													
21	PT EVER3	403	229,535	83.6	95.8	88.8	9,802	Heavy Oil BBLS ->	349,984	6,400,001	2,239,900	5,867,665	2.5563
22			21,137					Gas MCF ->	216,577	1,000,000	216,577	560,718	2.6528
23													
24	PT EVER4	402	97,962	34.8	88.6	88.6	9,792	Heavy Oil BBLS ->	149,387	6,400,000	956,077	2,504,549	2.5567
25			6,103					Gas MCF ->	62,541	1,000,000	62,541	161,919	2.6531
26													
27	RIV 3	280	106,673	51.2	78.3	82.9	10,250	Heavy Oil BBLS ->	169,810	6,400,001	1,086,785	2,676,802	2.5094
28													
29	RIV 4	280	124,282	59.7	92.5	82.1	10,226	Heavy Oil BBLS ->	197,637	6,400,001	1,264,876	3,115,447	2.5068
30													

Date: 9/3/99
Company: *Florida Power & Light*

Schedule E4
Page: 29

Estimated For The Period of : Oct-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	839	592,920	95.0	95.0	100.0	10,825	Nuclear MBTU ->	6,418,426	1,000,000	6,418,426	1,906,272	0.3215
33	ST LUC 2	714	504,597	95.0	85.9	100.0	10,825	Nuclear MBTU ->	5,462,290	1,000,000	5,462,290	1,674,192	0.3318
35	CAP CN 1	388	216,501	75.0	94.4	84.5	9,791	Heavy Oil BBLS ->	330,866	6,399,999	2,117,541	5,477,845	2.5302
37	CAP CN 2	403	206,931	69.0	81.0	82.0	9,903	Heavy Oil BBLS ->	319,623	6,400,000	2,045,589	5,291,712	2.5572
39	SANFRD 3	142	18,910	17.9	97.4	67.8	11,106	Heavy Oil BBLS ->	32,388	6,399,993	207,282	528,936	2.7972
41	SANFRD 4	383	166,728	58.5	94.5	81.6	10,397	Heavy Oil BBLS ->	269,965	6,400,000	1,727,779	4,408,902	2.6444
43	SANFRD 5	383	142,094	49.9	94.5	78.4	10,541	Heavy Oil BBLS ->	233,145	6,400,001	1,492,130	3,807,579	2.6796
45	PUTNAM 1	245	171,473	94.1	90.7	99.7	8,201	Gas MCF ->	1,406,121	1,000,000	1,406,121	3,640,448	2.1230
47	PUTNAM 2	245	164,615	90.3	87.8	99.3	8,206	Gas MCF ->	1,349,610	1,000,000	1,349,610	3,494,141	2.1226
49	MANATE 1	798	115,717	19.5	94.2	50.4	10,906	Heavy Oil BBLS ->	197,192	6,400,000	1,262,027	3,190,328	2.7570
51	MANATE 2	792		.0	82.8		0						
53	FT MY 1	141	66,831	63.7	95.8	90.9	10,471	Heavy Oil BBLS ->	109,346	6,400,004	699,815	1,681,807	2.5165
55	FT MY 2	397	270,144	91.5	94.0	97.3	9,529	Heavy Oil BBLS ->	402,224	6,400,001	2,574,233	6,186,439	2.2901
57	CUTLER 5	71	1,798	3.4	97.9	29.1	16,043	Gas MCF ->	27,804	1,000,000	27,804	71,984	4.0033
59	CUTLER 6	144	4,669	4.4	97.3	31.4	13,837	Gas MCF ->	63,312	1,000,000	63,312	163,916	3.5108

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 30

Estimated For The Period of : Oct-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 1	814	5,116	16.3	95.4	58.1	10,946	Heavy Oil BBLS ->	8,296	6,399,961	53,093	138,539	2.7077
62			93,435					Gas MCF ->	1,018,058	1,000,000	1,018,058	2,635,753	2.8209
64	MARTIN 2	813	57,297	34.4	95.7	64.7	10,678	Heavy Oil BBLS ->	91,847	6,400,000	587,821	1,533,848	2.6770
65			150,581					Gas MCF ->	1,622,088	1,000,000	1,622,088	4,199,584	2.7889
67	MARTIN 3	465	325,927	94.2	92.7	100.0	7,273	Gas MCF ->	2,370,378	1,000,000	2,370,378	6,136,908	1.8829
69	MARTIN 4	465	326,365	94.3	91.6	100.0	7,191	Gas MCF ->	2,346,755	1,000,000	2,346,755	6,075,750	1.8616
71	FM GT	552	37,089	9.0	97.0	99.8	13,702	Light Oil BBLS ->	87,620	5,799,998	508,196	2,041,423	5.5041
73	FL GT	684	4,520	3.8	95.0	87.9	15,462	Light Oil BBLS ->	11,544	5,830,013	67,304	273,860	6.0591
74			14,904					Gas MCF ->	233,024	1,000,000	233,024	603,300	4.0480
76	PE GT	336	4,583	1.8	95.0	87.8	18,213	Gas MCF ->	83,465	1,000,000	83,465	216,091	4.7154
78	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,752	Coal TONS ->	33,695	25,567,036	861,486	1,005,893	1.1387
80	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,637	Coal TONS ->	33,137	25,567,031	847,215	989,229	1.1253
82	SCHER #4	578	429,481	99.8	93.3	99.8	10,355	Coal TONS ->	254,140	17,500,001	4,447,445	7,313,061	1.7028
84	TOTAL	15,863	6,153,144				9,657				59,418,869	108,885,032	1.7696

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 31

Estimated For The Period of : Nov-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	404	50,568	17.4	86.8	50.3	10,057	Heavy Oil BBLS ->	78,693	6,399,999	503,635	1,334,369	2.6387
2													
3	TRKY O 2	403	59,213	20.4	92.1	50.0	10,034	Heavy Oil BBLS ->	91,516	6,399,998	585,702	1,551,806	2.6207
4													
5	TRKY N 3	717	490,380	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,575,040	1,000,000	4,575,040	1,416,890	0.2889
6													
7	TRKY N 4	717	408,649	79.2	85.9	100.0	9,330	Nuclear MBTU ->	3,812,548	1,000,000	3,812,548	1,201,334	0.2940
8													
9	FT LAUD4	452	298,063	91.6	91.9	97.0	7,742	Gas MCF ->	2,307,536	1,000,000	2,307,536	6,468,022	2.1700
10													
11	FT LAUD5	452	295,530	90.8	91.9	96.1	7,777	Gas MCF ->	2,298,480	1,000,000	2,298,480	6,442,637	2.1800
12													
13	PT EVER1	212	942	.6	92.9	25.3	12,933	Heavy Oil BBLS ->	1,831	6,399,880	11,717	30,692	3.2592
14													
15	PT EVER2	212	1,447	.9	92.6	28.9	12,211	Heavy Oil BBLS ->	2,664	6,399,962	17,046	44,652	3.0856
16													
17	PT EVER3	406	110,859	37.9	95.8	60.8	10,115	Heavy Oil BBLS ->	174,265	6,399,999	1,115,295	2,921,440	2.6353
18													
19	PT EVER4	402	54,763	18.9	88.6	54.6	10,145	Heavy Oil BBLS ->	86,234	6,400,003	551,896	1,445,654	2.6398
20													
21	RIV 3	282	55,265	27.2	78.3	54.0	10,543	Heavy Oil BBLS ->	89,900	6,399,998	575,359	1,414,031	2.5586
22													
23	RIV 4	282	60,346	29.7	92.5	58.1	10,407	Heavy Oil BBLS ->	97,175	6,399,998	621,919	1,528,461	2.5328
24													
25	ST LUC 1	853	583,370	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,237,773	1,000,000	6,237,773	1,853,866	0.3178
26													
27	ST LUC 2	726	496,468	95.0	85.9	100.0	10,693	Nuclear MBTU ->	5,308,587	1,000,000	5,308,587	1,628,144	0.3279
28													
29	CAP CN 1	391	126,745	45.0	94.4	62.0	9,928	Heavy Oil BBLS ->	195,705	6,400,001	1,252,513	3,222,303	2.5424
30													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 32

Estimated For The Period of : Nov-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	406	107,452	36.8	81.0	54.5	10,079	Heavy Oil BBLS ->	168,325	6,400,002	1,077,282	2,771,491	2.5793
33	SANFRD 3	147	4,586	4.3	97.4	60.3	11,306	Heavy Oil BBLS ->	7,810	6,399,969	49,981	127,079	2.7711
35	SANFRD 4	385	72,391	26.1	94.5	54.5	10,535	Heavy Oil BBLS ->	118,307	6,399,999	757,165	1,925,125	2.6594
37	SANFRD 5	385	67,885	24.5	94.5	54.8	10,690	Heavy Oil BBLS ->	112,503	6,400,001	720,019	1,830,679	2.6968
39	PUTNAM 1	250	99,887	55.5	90.7	64.8	8,681	Gas MCF ->	865,627	1,000,000	865,627	2,426,351	2.4291
41	PUTNAM 2	250	141,267	78.5	87.8	90.2	8,239	Gas MCF ->	1,162,070	1,000,000	1,162,070	3,257,281	2.3058
43	MANATE 1	800	35,223	6.1	94.2	31.1	11,373	Heavy Oil BBLS ->	62,591	6,400,007	400,581	1,016,509	2.8860
45	MANATE 2	799	20,255	3.5	82.8	41.4	10,983	Heavy Oil BBLS ->	34,760	6,399,999	222,466	564,527	2.7871
47	FT MY 1	142	48,072	47.0	95.8	72.7	10,527	Heavy Oil BBLS ->	79,067	6,400,002	506,030	1,211,534	2.5203
49	FT MY 2	400	208,999	72.6	94.0	78.2	9,598	Heavy Oil BBLS ->	313,448	6,400,001	2,006,070	4,802,922	2.2981
51	CUTLER 5	72	118	.2	97.9	27.5	17,332	Gas MCF ->	1,810	1,000,000	1,810	5,072	4.2874
53	CUTLER 6	145	348	.3	97.3	27.0	14,422	Gas MCF ->	4,736	1,000,000	4,736	13,276	3.8193
55	MARTIN 1	821	15,753	3.8	95.4	46.6	10,707	Heavy Oil BBLS ->	25,617	6,399,994	163,948	429,949	2.7293
56			6,751					Gas MCF ->	73,777	1,000,000	73,777	206,796	3.0631
58	MARTIN 2	830	53,457	12.8	95.7	46.2	10,586	Heavy Oil BBLS ->	86,256	6,400,000	552,041	1,447,713	2.7082
59			22,910					Gas MCF ->	248,418	1,000,000	248,418	696,317	3.0393

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 33

Estimated For The Period of : Nov-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	492	328,773	92.8	92.7	98.5	7,172	Gas	MCF ->	2,357,886	1,000,000	2,357,886	6,609,155	2.0103
62														
63	MARTIN 4	492	331,459	93.6	91.6	99.2	7,075	Gas	MCF ->	2,345,223	1,000,000	2,345,223	6,573,659	1.9832
64														
65	FM GT	624	1,235	.3	97.0	88.9	13,247	Light Oil	BBLS ->	2,820	5,800,007	16,357	62,891	5.0936
66														
67	FL GT	768	3	.0	95.0		19,819	Gas	MCF ->	63	1,000,000	63	175	5.4688
68														
69	PE GT	384	133	.0	95.0	79.5	21,235	Gas	MCF ->	2,832	1,000,000	2,832	7,939	5.9513
70														
71	SJRPP 1O	119	85,487	100.0	93.3	100.0	9,655	Coal	TONS ->	32,241	25,600,033	825,381	965,077	1.1289
72														
73	SJRPP 2O	118	85,073	100.0	85.5	100.0	9,542	Coal	TONS ->	31,711	25,600,014	811,805	949,203	1.1158
74														
75	SCHER #4	578	409,084	98.2	93.3	98.2	10,256	Coal	TONS ->	239,739	17,499,997	4,195,423	6,910,231	1.6892
76														
77	TOTAL	16,318	5,239,207				9,380					49,142,033	77,315,252	1.4757

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 34

Estimated For The Period of : Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	404	32,849	10.9	86.8	38.8	10,498	Heavy Oil BBLS ->	53,083	6,400,001	339,732	886,072	2.6974
3	TRKY O 2	403	42,343	14.1	92.1	41.0	10,366	Heavy Oil BBLS ->	67,305	6,400,000	430,754	1,123,471	2.6532
5	TRKY N 3	717	506,727	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,727,536	1,000,000	4,727,536	1,465,063	0.2891
7	TRKY N 4	717	506,727	95.0	85.9	100.0	9,330	Nuclear MBTU ->	4,727,536	1,000,000	4,727,536	1,491,537	0.2943
9	FT LAUD4	452	299,397	89.0	91.9	94.9	7,764	Gas MCF ->	2,324,178	1,000,000	2,324,178	6,946,968	2.3203
11	FT LAUD5	452	296,312	88.1	91.9	94.2	7,798	Gas MCF ->	2,310,176	1,000,000	2,310,176	6,905,115	2.3304
13	PT EVER1	212	9	.0	92.9	65.9	10,522	Heavy Oil BBLS ->	14	6,375,887	90	230	2.7059
15	PT EVER2	212	1,525	1.0	92.6	29.2	12,158	Heavy Oil BBLS ->	2,799	6,400,000	17,910	45,793	3.0038
17	PT EVER3	406	56,339	18.7	95.8	40.5	10,734	Heavy Oil BBLS ->	93,478	6,400,000	598,262	1,529,634	2.7150
19	PT EVER4	402	54,960	18.4	88.6	45.2	10,394	Heavy Oil BBLS ->	88,303	6,400,004	565,142	1,444,953	2.6291
21	RIV 3	282	103,417	49.3	78.3	62.6	10,347	Heavy Oil BBLS ->	166,297	6,400,002	1,064,298	2,470,962	2.3893
23	RIV 4	282	120,852	57.6	92.5	68.8	10,229	Heavy Oil BBLS ->	192,514	6,399,999	1,232,088	2,860,518	2.3670
25	ST LUC 1	853	602,816	95.0	95.0	100.0	10,693	Nuclear MBTU ->	6,445,699	1,000,000	6,445,699	1,916,306	0.3179
27	ST LUC 2	726	513,017	95.0	85.9	100.0	10,693	Nuclear MBTU ->	5,485,540	1,000,000	5,485,540	1,683,512	0.3282
29	CAP CN 1	391	108,310	37.2	94.4	50.3	10,084	Heavy Oil BBLS ->	169,753	6,399,998	1,086,418	2,673,453	2.4683

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 35

Estimated For The Period of : Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	CAP CN 2	406	112,920	37.4	81.0	52.2	10,104	Heavy Oil BBLS ->	177,381	6,399,999	1,135,238	2,793,591	2.4739
33	SANFRD 3	147	6,888	6.3	97.4	54.9	11,510	Heavy Oil BBLS ->	11,825	6,400,014	75,678	182,504	2.6496
35	SANFRD 4	385	130,686	45.6	94.5	58.8	10,502	Heavy Oil BBLS ->	213,666	6,400,002	1,367,462	3,297,775	2.5234
37	SANFRD 5	385	85,834	30.0	94.5	55.4	10,677	Heavy Oil BBLS ->	142,303	6,400,000	910,740	2,196,343	2.5588
39	PUTNAM 1	250	66,746	35.9	90.7	59.8	8,821	Gas MCF ->	584,920	1,000,000	584,920	1,748,326	2.6194
41	PUTNAM 2	250	86,298	46.4	87.8	78.4	8,393	Gas MCF ->	720,428	1,000,000	720,428	2,153,359	2.4953
43	MANATE 1	800	20,990	3.5	94.2	36.1	11,161	Heavy Oil BBLS ->	36,605	6,399,986	234,273	589,974	2.8108
45	MANATE 2	805	66,685	11.1	82.8	37.3	11,274	Heavy Oil BBLS ->	117,471	6,400,002	751,812	1,893,297	2.8392
47	FT MY 1	142	70,684	66.9	95.8	79.9	10,429	Heavy Oil BBLS ->	115,178	6,400,003	737,138	1,663,808	2.3539
49	FT MY 2	400	245,981	82.7	94.0	88.0	9,504	Heavy Oil BBLS ->	365,277	6,400,001	2,337,773	5,276,634	2.1451
51	CUTLER 5	72	1	.0	97.9		0	Gas MCF ->	13	1,000,000	13	38	3.8000
53	CUTLER 6	145	3	.0	97.3	72.2	12,027	Gas MCF ->	36	1,000,000	36	109	3.6333
55	MARTIN 1	821	3,869	.9	95.4	38.6	11,056	Heavy Oil BBLS ->	6,469	6,400,056	41,399	108,146	2.7953
56			1,658					Gas MCF ->	18,630	1,000,000	18,630	55,684	3.3583
58	MARTIN 2	830	28,423	6.6	95.7	42.9	10,779	Heavy Oil BBLS ->	46,540	6,400,000	297,855	778,076	2.7375
59			12,181					Gas MCF ->	134,035	1,000,000	134,035	400,629	3.2889

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 36

Estimated For The Period of : Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 3	492	338,321	92.4	92.7	98.1	7,176	Gas MCF ->	2,427,789	1,000,000	2,427,789	7,256,661	2.1449
62													
63	MARTIN 4	492	341,106	93.2	91.6	98.8	7,079	Gas MCF ->	2,414,766	1,000,000	2,414,766	7,217,734	2.1160
64													
65	FM GT	624	2	.0	97.0		12,921	Light Oil BBLS ->	5	5,792,453	31	113	4.7083
66													
67	FL GT	768	0	.0	95.0		0	Gas MCF ->	0	1,000,000	0	0	
68													
69	PE GT	384	0	.0	95.0		0	Gas MCF ->	1	1,000,000	1	4	4.0000
70													
71	SJRPP 1O	119	88,336	100.0	93.3	100.0	9,655	Coal TONS ->	33,272	25,633,975	852,894	998,587	1.1304
72													
73	SJRPP 2O	118	87,909	100.0	85.5	100.0	9,542	Coal TONS ->	32,725	25,633,989	838,865	982,162	1.1173
74													
75	SCHER #4	578	424,943	98.7	93.3	98.7	10,256	Coal TONS ->	249,049	17,500,002	4,358,362	7,188,836	1.6917
76													
77	TOTAL	16,324	5,466,060				9,439				51,595,491	80,225,977	1.4677

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 37

Estimated For The Period of : Jan-00 Thru Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	402	737,049	34.4	0.0	69.3	10,037	Heavy Oil BBLS ->	1,137,253	6,400,000	7,278,421	18,965,945	2.5732
2			475,030					Gas MCF ->	4,887,649	1,000,000	4,887,649	12,094,560	2.5626
3													
4	TRKY O 2	401	892,410	33.0	0.0	71.0	9,945	Heavy Oil BBLS ->	1,372,427	6,400,000	8,783,533	22,761,107	2.5505
5			270,150					Gas MCF ->	2,777,764	1,000,000	2,777,764	6,884,427	2.5484
6													
7	TRKY N 3	703	5,294,537	85.7	0.0	99.8	9,507	Nuclear MBTU ->	50,335,015	1,000,000	50,335,015	15,650,997	0.2956
8													
9													
10	TRKY N 4	703	5,309,857	86.0	0.0	100.0	9,483	Nuclear MBTU ->	50,353,893	1,000,000	50,353,893	14,893,429	0.2805
11													
12	FT LAUD4	439	3,476,205	90.1	0.0	98.2	7,769	Gas MCF ->	27,008,240	1,000,000	27,008,240	71,700,000	2.0626
13													
14	FT LAUD5	439	3,465,852	89.8	0.0	98.0	7,798	Gas MCF ->	27,026,199	1,000,000	27,026,199	71,688,313	2.0684
15													
16	PT EVER1	211	127,437	7.6	0.0	77.8	10,814	Heavy Oil BBLS ->	214,564	6,399,998	1,373,206	3,560,745	2.7941
17			14,105					Gas MCF ->	157,420	1,000,000	157,420	367,894	2.6083
18													
19	PT EVER2	211	314,921	19.3	0.0	73.8	10,627	Heavy Oil BBLS ->	520,579	6,400,000	3,331,708	8,641,374	2.7440
20			43,934					Gas MCF ->	481,856	1,000,000	481,856	1,135,335	2.5842
21													
22	PT EVER3	404	2,084,682	60.1	0.0	78.1	9,863	Heavy Oil BBLS ->	3,210,150	6,400,000	20,544,964	52,995,962	2.5422
23			48,925					Gas MCF ->	499,678	1,000,000	499,678	1,222,325	2.4984
24													
25	PT EVER4	402	1,653,846	50.0	0.0	78.4	9,868	Heavy Oil BBLS ->	2,543,509	6,400,001	16,278,458	41,974,171	2.5380
26			110,654					Gas MCF ->	1,133,054	1,000,000	1,133,054	2,663,708	2.4072
27													
28	RIV 3	281	1,049,873	42.6	0.0	75.8	10,217	Heavy Oil BBLS ->	1,676,021	6,400,000	10,726,531	25,574,546	2.4360
29													
30													

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 38

Estimated For The Period of : Jan-00 Thru Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	RIV 4	281	1,426,560	57.8	0.0	78.1	10,173	Heavy Oil BBLS ->	2,267,651	6,400,000	14,512,968	34,434,558	2.4138
33	ST LUC 1	845	7,048,803	95.0	0.0	100.0	10,770	Nuclear MBTU ->	75,912,553	1,000,000	75,912,553	23,217,965	0.3294
35	ST LUC 2	719	5,429,074	86.0	0.0	100.0	10,764	Nuclear MBTU ->	58,437,153	1,000,000	58,437,153	18,180,729	0.3349
37	CAP CN 1	389	2,200,942	64.4	0.0	76.4	9,818	Heavy Oil BBLS ->	3,376,280	6,400,000	21,608,194	54,210,627	2.4631
39	CAP CN 2	402	1,646,629	46.6	0.0	76.0	9,925	Heavy Oil BBLS ->	2,553,455	6,400,000	16,342,114	41,133,353	2.4980
42	SANFRD 3	144	188,427	14.9	0.0	80.0	10,894	Heavy Oil BBLS ->	320,727	6,400,000	2,052,650	5,084,203	2.6982
45	SANFRD 4	384	1,883,489	55.9	0.0	76.8	10,348	Heavy Oil BBLS ->	3,045,463	6,400,001	19,490,962	47,922,287	2.5443
47	SANFRD 5	384	1,547,597	45.9	0.0	75.4	10,487	Heavy Oil BBLS ->	2,535,923	6,400,000	16,229,906	39,910,392	2.5789
49	PUTNAM 1	247	1,693,913	78.0	0.0	91.5	8,262	Gas MCF ->	13,995,636	1,000,000	13,995,636	36,270,356	2.1412
51	PUTNAM 2	247	1,517,642	69.9	0.0	87.0	8,323	Gas MCF ->	12,631,761	1,000,000	12,631,761	32,922,383	2.1693
53	MANATE 1	799	1,140,583	16.3	0.0	60.6	10,765	Heavy Oil BBLS ->	1,918,579	6,400,000	12,278,908	31,277,789	2.7423
55	MANATE 2	795	1,999,770	28.6	0.0	69.3	10,652	Heavy Oil BBLS ->	3,328,411	6,400,000	21,301,830	54,115,216	2.7061
58	FT MY 1	141	766,701	61.7	0.0	84.8	10,478	Heavy Oil BBLS ->	1,255,185	6,400,000	8,033,183	18,579,301	2.4233
60	FT MY 2	398	2,989,226	85.4	0.0	91.7	9,536	Heavy Oil BBLS ->	4,453,815	6,400,000	28,504,415	65,973,389	2.2070

Date: 9/3/99
Company: Florida Power & Light

Schedule E4
Page: 39

Estimated For The Period of : Jan-00 Thru Dec-00

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	CUTLER 5	71	20,852	3.3	0.0	49.1	14,011	Gas MCF ->	292,148	1,000,000	292,148	735,755	3.5285
64	CUTLER 6	144	56,937	4.5	0.0	57.9	12,562	Gas MCF ->	715,258	1,000,000	715,258	1,803,072	3.1668
66	MARTIN 1	817	368,953	11.5	0.0	65.4	10,545	Heavy Oil BBLS ->	591,117	6,399,999	3,783,150	9,637,399	2.6121
67			459,186					Gas MCF ->	4,949,781	1,000,000	4,949,781	12,451,073	2.7116
69	MARTIN 2	820	856,536	24.5	0.0	67.4	10,461	Heavy Oil BBLS ->	1,365,509	6,400,000	8,739,256	22,177,668	2.5892
70			907,468					Gas MCF ->	9,714,778	1,000,000	9,714,778	24,616,191	2.7126
72	MARTIN 3	476	3,853,262	92.1	0.0	97.8	7,240	Gas MCF ->	27,897,549	1,000,000	27,897,549	74,139,997	1.9241
74	MARTIN 4	476	3,820,123	91.3	0.0	96.8	7,160	Gas MCF ->	27,353,241	1,000,000	27,353,241	72,688,177	1.9028
76	FM GT	582	218,261	4.3	0.0	94.7	13,677	Light Oil BBLS ->	514,679	5,800,000	2,985,139	11,175,272	5.1201
78	FL GT	719	21,536	1.7	0.0	85.0	15,584	Light Oil BBLS ->	55,330	5,829,999	322,572	1,254,687	5.8261
79			83,531					Gas MCF ->	1,314,813	1,000,000	1,314,813	3,308,247	3.9605
81	PE GT	356	909	0.8	0.0	85.0	18,424	Light Oil BBLS ->	3,155	5,829,915	18,393	78,574	8.6440
82			23,897					Gas MCF ->	438,648	1,000,000	438,648	1,091,945	4.5693
84	SJRPP 1O	119	1,042,936	99.8	0.0	99.8	9,712	Coal TONS ->	397,532	25,479,612	10,128,966	11,773,652	1.1289
86	SJRPP 2O	118	952,818	91.9	0.0	100.0	9,603	Coal TONS ->	359,008	25,486,572	9,149,878	10,640,306	1.1167
88	SCHER #4	578	5,020,726	98.9	0.0	98.9	10,317	Coal TONS ->	2,959,862	17,500,000	51,797,581	84,964,432	1.6923
90	TOTAL	16,051	74,556,751				9,575				713,910,973	1,218,543,833	1.6344

Date:7/5/99
Company: Florida Power & Light

Schedule: E5
Page : 1

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2000 thru December 2000

			January 2000	February 2000	March 2000	April 2000	May 2000	June 2000
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	1,779,800	1,480,122	2,817,390	2,528,923	4,149,361	3,842,338
3	Unit Cost	($/BBLS)	15.4214	15.4028	14.8485	16.4892	16.4016	16.2820
4	Amount	($)	27,447,000	22,798,000	41,834,000	41,700,000	68,056,000	62,561,000
5								
6	Burned:							
7	Units	(BBLS)	1,879,800	1,530,122	2,667,390	2,328,923	3,949,361	3,892,338
8	Unit Cost	($/BBLS)	15.3063	15.3650	15.0781	15.8275	16.1137	16.1656
9	Amount	($)	28,772,751	23,510,310	40,219,124	36,861,089	63,638,900	62,922,081
10								
11	Ending Inventory:							
12	Units	(BBLS)	3,100,001	3,050,001	3,200,000	3,400,002	3,600,001	3,550,001
13	Unit Cost	($/BBLS)	15.4014	15.4206	15.2024	15.7310	16.0838	16.2086
14	Amount	($)	47,744,250	47,032,916	48,647,760	53,485,468	57,901,654	57,540,701
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	6,413	2,570	15,472	24	15,712	44,689
21	Unit Cost	($/BBLS)	23.2341	22.5681	21.7166	41.6667	22.0214	20.9000
22	Amount	($)	149,000	58,000	336,000	1,000	346,000	934,000
23								
24	Burned:							
25	Units	(BBLS)	10,924	2,570	15,472	24	15,712	44,768
26	Unit Cost	($/BBLS)	23.9393	22.6591	21.6859	22.3750	22.0404	20.9107
27	Amount	($)	261,513	58,234	335,524	537	346,299	936,130
28								
29	Ending Inventory:							
30	Units	(BBLS)	86,831	86,831	86,831	86,831	86,831	86,751
31	Unit Cost	($/BBLS)	27.8942	27.8942	27.8942	27.8942	27.8942	27.8971
32	Amount	($)	2,422,080	2,422,080	2,422,080	2,422,080	2,422,080	2,420,100
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	66,658	58,068	38,902	65,065	67,204	69,528
39	Unit Cost	($/Tons)	29.3138	29.3621	29.4072	29.4628	29.5221	29.5708
40	Amount	($)	1,954,000	1,705,000	1,144,000	1,917,000	1,984,000	2,056,000
41								
42	Burned:							
43	Units	(Tons)	66,658	58,068	38,902	65,065	67,204	65,006
44	Unit Cost	($/Tons)	29.2925	29.3398	29.3838	29.4398	29.4951	29.5492
45	Amount	($)	1,952,581	1,703,703	1,143,089	1,915,503	1,982,192	1,920,877
46								
47	Ending Inventory:							
48	Units	(Tons)	45,218	45,218	45,217	45,216	45,216	49,738
49	Unit Cost	($/Tons)	27.6072	27.6422	27.6730	27.7169	27.7592	27.9586
50	Amount	($)	1,248,344	1,249,926	1,251,292	1,253,247	1,255,159	1,390,606
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	4,386,340	3,939,303	4,236,400	4,259,150	4,448,535	4,602,378
57	Unit Cost	($/MBTU)	1.6380	1.6371	1.6370	1.6369	1.6360	1.6359
58	Amount	($)	7,185,000	6,449,000	6,935,000	6,972,000	7,278,000	7,529,000
59								
60	Burned:							
61	Units	(MBTU)	4,386,340	3,939,303	4,236,400	4,259,150	4,448,535	4,311,825
62	Unit Cost	($/MBTU)	1.6386	1.6377	1.6373	1.6371	1.6364	1.6362
63	Amount	($)	7,187,275	6,451,238	6,936,127	6,972,698	7,279,758	7,054,880
64								
65	Ending Inventory:							
66	Units	(MBTU)	2,905,543	2,905,543	2,905,543	2,905,508	2,905,508	3,196,078
67	Unit Cost	($/MBTU)	1.6386	1.6377	1.6373	1.6371	1.6365	1.6362
68	Amount	($)	4,760,898	4,758,295	4,757,156	4,756,692	4,754,743	5,229,356
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	10,435,143	11,522,677	11,821,410	13,418,232	12,819,118	17,466,386
75	Unit Cost	($/MCF)	3.9869	3.3280	3.2458	3.1691	3.4373	3.1451
76	Amount	($)	41,603,920	38,347,010	38,370,210	42,523,740	44,063,760	54,934,080
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	21,386,310	19,701,576	16,658,774	17,836,594	17,593,735	20,607,093
83	Unit Cost	($/MBTU)	0.3064	0.3069	0.3092	0.3071	0.3071	0.3085
84	Amount	($)	6,553,152	6,046,014	5,151,450	5,478,108	5,403,523	6,356,782

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2000 thru December 2000

			July 2000	August 2000	September 2000	October 2000	November 2000	December 2000	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	5,450,427	5,142,725	3,643,165	3,059,451	1,726,667	2,066,258	37,686,627
3	Unit Cost	($/BBLS)	16.4620	15.5569	15.5239	16.8785	16.1832	14.6802	15.9366
4	Amount	($)	89,725,000	80,005,000	56,556,000	51,639,000	27,943,000	30,333,000	600,597,000
5									
6	Burned:								
7	Units	(BBLS)	5,350,427	5,342,725	3,643,165	3,209,451	1,826,667	2,066,258	37,686,627
8	Unit Cost	($/BBLS)	16.3540	15.8855	15.6198	16.2929	16.2158	15.3975	15.8924
9	Amount	($)	87,501,116	84,872,016	56,905,516	52,291,145	29,620,933	31,815,245	598,930,226
10									
11	Ending Inventory:								
12	Units	(BBLS)	3,650,008	3,450,009	3,449,998	3,300,003	3,200,001	3,200,001	3,200,001
13	Unit Cost	($/BBLS)	16.3738	15.9125	15.8114	16.3322	16.3182	15.8552	15.8552
14	Amount	($)	59,764,575	54,898,244	54,549,142	53,896,453	52,218,355	50,736,810	50,736,810
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	109,865	192,868	71,698	99,164	2,820	5	561,300
21	Unit Cost	($/BBLS)	20.8529	21.2477	22.6227	23.3452	22.3404	0.0000	21.7584
22	Amount	($)	2,291,000	4,098,000	1,622,000	2,315,000	63,000	0	12,213,000
23									
24	Burned:								
25	Units	(BBLS)	117,137	192,868	71,698	99,164	2,820	5	573,162
26	Unit Cost	($/BBLS)	21.1036	21.2451	22.6297	23.3480	22.3018	22.6000	21.8237
27	Amount	($)	2,472,007	4,097,498	1,622,505	2,315,283	62,891	113	12,508,534
28									
29	Ending Inventory:								
30	Units	(BBLS)	79,479	79,479	79,479	79,479	79,479	79,479	79,479
31	Unit Cost	($/BBLS)	28.1708	28.1708	28.1708	28.1708	28.1708	28.1708	28.1708
32	Amount	($)	2,238,985	2,238,985	2,238,985	2,238,985	2,238,985	2,238,985	2,238,985
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	67,088	67,004	64,759	62,309	63,954	65,998	756,537
39	Unit Cost	($/Tons)	29.6476	29.7296	29.8028	29.8833	29.9590	30.0464	29.6509
40	Amount	($)	1,989,000	1,992,000	1,930,000	1,862,000	1,916,000	1,983,000	22,432,000
41									
42	Burned:								
43	Units	(Tons)	67,088	67,004	64,759	66,831	63,954	65,998	756,537
44	Unit Cost	($/Tons)	29.6236	29.6999	29.7764	29.8526	29.9327	30.0128	29.6269
45	Amount	($)	1,987,388	1,990,014	1,928,293	1,995,082	1,914,315	1,980,788	22,413,825
46									
47	Ending Inventory:								
48	Units	(Tons)	49,738	49,738	49,738	45,216	45,218	45,218	45,218
49	Unit Cost	($/Tons)	27.9957	28.0349	28.0730	27.9364	27.9768	28.0171	28.0171
50	Amount	($)	1,392,448	1,394,398	1,396,295	1,263,173	1,265,055	1,266,878	1,266,878
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	4,456,043	4,456,043	4,302,690	4,156,898	4,195,415	4,358,358	51,797,550
57	Unit Cost	($/MBTU)	1.6389	1.6409	1.6441	1.6459	1.6489	1.6511	1.6409
58	Amount	($)	7,303,000	7,312,000	7,074,000	6,842,000	6,918,000	7,196,000	84,993,000
59									
60	Burned:								
61	Units	(MBTU)	4,456,043	4,456,043	4,302,690	4,447,450	4,195,415	4,358,358	51,797,550
62	Unit Cost	($/MBTU)	1.6378	1.6397	1.6422	1.6443	1.6471	1.6494	1.6403
63	Amount	($)	7,298,193	7,306,451	7,065,682	7,313,061	6,910,231	7,188,836	84,964,430
64									
65	Ending Inventory:								
66	Units	(MBTU)	3,196,060	3,196,060	3,196,060	2,905,508	2,905,543	2,905,543	2,905,543
67	Unit Cost	($/MBTU)	1.6378	1.6397	1.6422	1.6443	1.6471	1.6494	1.6494
68	Amount	($)	5,234,624	5,240,547	5,248,486	4,777,670	4,785,691	4,792,510	4,792,510
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	14,365,517	14,748,150	19,349,854	15,484,197	11,745,653	11,012,332	164,188,669
75	Unit Cost	($/MCF)	3.3889	3.1734	2.8899	3.1675	3.5073	3.7655	3.3069
76	Amount	($)	48,683,570	46,801,410	55,918,370	49,046,060	41,195,520	41,466,560	542,954,210
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	21,294,000	21,294,000	20,607,093	16,739,185	19,933,948	21,386,310	235,038,618
83	Unit Cost	($/MBTU)	0.3041	0.3041	0.3041	0.3035	0.3060	0.3066	0.3061
84	Amount	($)	6,475,700	6,475,541	6,265,970	5,080,228	6,100,234	6,556,418	71,943,120

Date:8/3/99
Company: Florida Power & Light

Schedule: E6
Page : 1

POWER SOLD

Estimated For the Period of : January 2000 Thru December 2000

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For uel Adjustment (6) * (7A)
		C	750		750	2.429	2.729	18,217
January		OS	243,643		243,643	2.429	2.751	5,918,089
2000		S			0			0
	St.Lucie Rel.		44,895		44,895	0.336	0.336	150,830
	80% of Gain							1,800
Total			289,288	0	289,288	2.104	2.376	6,088,936
		C	750		750	2.309	2.709	17,318
February		OS	201,719		201,719	2.309	2.631	4,657,692
2000		S			0			0
	St.Lucie Rel.		41,998		41,998	0.337	0.337	141,420
	80% of Gain							2,400
Total			244,467	0	244,467	1.970	2.237	4,818,830
		C	750		750	2.445	2.745	18,338
March		OS	287,900		287,900	2.445	2.767	7,039,155
2000		S			0			0
	St.Lucie Rel.		44,894		44,894	0.336	0.336	150,640
	80% of Gain							1,800
Total			333,544	0	333,544	2.161	2.440	7,209,933
		C	500		500	2.545	3.245	12,725
April		OS	116,244		116,244	2.545	2.967	2,958,410
2000		S			0			0
	St.Lucie Rel.		42,735		42,735	0.335	0.335	143,130
	80% of Gain							2,800
Total			159,479	0	159,479	1.953	2.263	3,117,065
		C	100		100	2.675	2.975	2,675
May		OS	117,925		117,925	2.675	3.297	3,154,494
2000		S			0			0
	St.Lucie Rel.		44,160		44,160	0.334	0.334	147,570
	80% of Gain							240
Total			162,185	0	162,185	2.038	2.490	3,304,979
		C	100		100	2.945	3.245	2,945
June		OS	153,000		153,000	2.945	7.167	4,505,850
2000		S			0			0
	St.Lucie Rel.		42,735		42,735	0.335	0.335	142,990
	80% of Gain							240
Total			195,835	0	195,835	2.375	5.674	4,652,025

Date:8/3/99
Company: Florida Power & Light

Schedule: E6
Page : 2

POWER SOLD

Estimated For the Period of : January 2000 Thru December 2000

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH)	(8) Total $ For uel Adjustment (6) * (7A)
		C	100		100	3.135	3.335	3,135
July		OS	204,000		204,000	3.135	7.557	6,395,400
2000		S			0			0
	St.Lucie Rel.		44,160		44,160	0.329	0.329	145,080
	80% of Gain							160
Total			248,260	0	248,260	2.636	6.270	6,543,775
		C	100		100	2.846	3.146	2,846
August		OS	204,000		204,000	2.846	4.568	5,805,840
2000		S			0			0
	St.Lucie Rel.		44,160		44,160	0.328	0.328	144,840
	80% of Gain							240
Total			248,260	0	248,260	2.398	3.813	5,953,766
		C	100		100	2.850	3.350	2,850
September		OS	153,000		153,000	2.850	4.572	4,360,500
2000		S			0			0
	St.Lucie Rel.		42,735		42,735	0.327	0.327	139,940
	80% of Gain							400
Total			195,835	0	195,835	2.300	3.645	4,503,690
		C	750		750	2.775	3.275	20,813
October		OS	51,000		51,000	2.775	2.997	1,415,250
2000		S			0			0
	St.Lucie Rel.		44,160		44,160	0.321	0.321	141,970
	80% of Gain							3,000
Total			95,910	0	95,910	1.645	1.767	1,581,033
		C	750		750	2.504	2.904	18,780
November		OS	51,000		51,000	2.504	2.726	1,277,040
2000		S			0			0
	St.Lucie Rel.		43,447		43,447	0.318	0.318	138,070
	80% of Gain							2,400
Total			95,197	0	95,197	1.506	1.628	1,436,290
		C	750		750	2.372	2.772	17,790
December		OS	51,000		51,000	2.372	2.694	1,209,720
2000		S			0			0
	St.Lucie Rel.		44,895		44,895	0.318	0.318	142,720
	80% of Gain							2,400
Total			96,645	0	96,645	1.418	1.591	1,372,630
		C	5,500		5,500	2.517	2.923	138,432
Period		OS	1,634,431		1,634,431	2.655	4.050	48,697,440
Total		S	0		0			0
	St.Lucie Rel.		524,974		524,974	0.329	0.329	1,729,200
	80% of Gain							17,880
Total			2,364,905	0	2,364,905	2.138	3.222	50,582,952

Date: 8/3/99
Company: Florida Power & Light

Schedule: E7
Page : 1

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2000 thru December 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2000	Sou. Co. (UPS • R)		926,057			926,057	1.602		14,838,310
January	St. Lucie Rel.		44,894			44,894	0.337		151,100
	SJRPP		264,344			264,344	1.109		2,930,980
Total			1,235,295			1,235,295	1.451		17,920,390
2000	Sou. Co. (UPS + R)		840,374			840,374	1.566		13,157,530
February	St. Lucie Rel.		41,997			41,997	0.337		141,500
	SJRPP		230,275			230,275	1.111		2,557,660
Total			1,112,646			1,112,646	1.425		15,856,690
2000	Sou. Co. (UPS + R)		875,148			875,148	1.625		14,222,120
March	St. Lucie Rel.		44,894			44,894	0.337		151,300
	SJRPP		153,748			153,748	1.116		1,716,420
Total			1,073,790			1,073,790	1.498		16,089,840
2000	Sou. Co. (UPS + R)		576,405			576,405	1.532		8,830,350
April	St. Lucie Rel.		22,791			22,791	0.336		76,600
	SJRPP		255,817			255,817	1.124		2,875,980
Total			855,013			855,013	1.378		11,782,930
2000	Sou. Co. (UPS + R)		644,301			644,301	1.677		10,801,620
May	St. Lucie Rel.		14,245			14,245	0.338		48,200
	SJRPP		264,344			264,344	1.126		2,975,950
Total			922,890			922,890	1.498		13,825,770
2000	Sou. Co. (UPS + R)		596,113			596,113	1.606		9,571,390
June	St. Lucie Rel.		42,734			42,734	0.339		144,900
	SJRPP		255,817			255,817	1.127		2,883,680
Total			894,664			894,664	1.408		12,599,970

Date: 8/3/99
Company: Florida Power & Light

Schedule: E7
Page : 2

Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2000 thru December 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2000	Sou. Co. (UPS + R)		613,129			613,129	1.591		9,754,490
July	St. Lucie Rel.		44,158			44,158	0.336		148,500
	SJRPP		264,344			264,344	1.129		2,983,650
Total			921,631			921,631	1.398		12,886,640
2000	Sou. Co. (UPS + R)		614,262			614,262	1.607		9,868,200
August	St. Lucie Rel.		44,158			44,158	0.337		148,700
	SJRPP		264,344			264,344	1.130		2,987,740
Total			922,764			922,764	1.409		13,004,640
2000	Sou. Co. (UPS + R)		629,433			629,433	1.593		10,027,890
September	St. Lucie Rel.		42,734			42,734	0.337		144,000
	SJRPP		255,817			255,817	1.132		2,895,080
Total			927,984			927,984	1.408		13,066,970
2000	Sou. Co. (UPS + R)		790,672			790,672	1.605		12,689,880
October	St. Lucie Rel.		44,158			44,158	0.332		146,500
	SJRPP		264,344			264,344	1.133		2,995,430
Total			1,099,174			1,099,174	1.440		15,831,810
2000	Sou. Co. (UPS + R)		819,439			819,439	1.555		12,742,490
November	St. Lucie Rel.		43,445			43,445	0.328		142,500
	SJRPP		255,817			255,817	1.123		2,874,000
Total			1,118,701			1,118,701	1.409		15,758,990
2000	Sou. Co. (UPS + R)		855,879			855,879	1.553		13,295,040
December	St. Lucie Rel.		44,894			44,894	0.328		147,300
	SJRPP		264,344			264,344	1.125		2,973,610
Total			1,165,117			1,165,117	1.409		16,415,950
	Sou. Co. (UPS + R)		8,781,212			8,781,212	1.592		139,799,310
Period	St. Lucie Rel.		475,102			475,102	0.335		1,591,100
Total	SJRPP		2,993,355			2,993,355	1.124		33,650,180
Total			12,249,669			12,249,669	1.429		175,040,590

Date: 8/3/99
Company: Florida Power & Light

Schedule: E8
Page : 1

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2000 thru December 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2000 January	Qual. Facilities		570,277			570,277	1.752	1.752	9,993,623
Total			570,277			570,277	1.752	1.752	9,993,623
2000 February	Qual. Facilities		504,380			504,380	1.713	1.713	8,641,208
Total			504,380			504,380	1.713	1.713	8,641,208
2000 March	Qual. Facilities		555,464			555,464	1.731	1.731	9,615,741
Total			555,464			555,464	1.731	1.731	9,615,741
2000 April	Qual. Facilities		526,949			526,949	1.939	1.939	10,216,975
Total			526,949			526,949	1.939	1.939	10,216,975
2000 May	Qual. Facilities		602,111			602,111	1.833	1.833	11,038,972
Total			602,111			602,111	1.833	1.833	11,038,972
2000 June	Qual. Facilities		612,298			612,298	1.849	1.849	11,319,311
Total			612,298			612,298	1.849	1.849	11,319,311

Date: 8/3/99
Company: Florida Power & Light

Schedule: E8
Page : 2

Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2000 thru December 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2000 July	Qual. Facilities		647,632			647,632	1.872	1.872	12,126,687
Total			647,632			647,632	1.872	1.872	12,126,687
2000 August	Qual. Facilities		628,498			628,498	1.853	1.853	11,648,742
Total			628,498			628,498	1.853	1.853	11,648,742
2000 September	Qual. Facilities		599,435			599,435	1.846	1.846	11,062,787
Total			599,435			599,435	1.846	1.846	11,062,787
2000 October	Qual. Facilities		613,639			613,639	1.852	1.852	11,366,584
Total			613,639			613,639	1.852	1.852	11,366,584
2000 November	Qual. Facilities		391,525			391,525	1.932	1.932	7,564,619
Total			391,525			391,525	1.932	1.932	7,564,619
2000 December	Qual. Facilities		480,124			480,124	1.633	1.633	7,841,415
Total			480,124			480,124	1.633	1.633	7,841,415
Period Total	Qual. Facilities		6,732,332			6,732,332	1.819	1.819	122,436,664
Total			6,732,332			6,732,332	1.819	1.819	122,436,664

Date:8/3/99
Company: Florida Power & Light

Schedule: E9
Page : 1

Economy Energy Purchases

Estimated For the Period of : January 2000 Thru December 2000

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
January 2000	Florida	C	110,025	1.783	1,962,180	1.834	2,018,293	56,113
	Non-Florida	C	108,099	1.874	2,025,750	1.925	2,080,880	55,130
Total			218,124	1.828	3,987,930	1.879	4,099,173	111,243
February 2000	Florida	C	89,438	1.781	1,592,650	1.807	1,615,904	23,254
	Non-Florida	C	95,121	1.692	1,609,440	1.718	1,634,171	24,731
Total			184,559	1.735	3,202,090	1.761	3,250,075	47,985
March 2000	Florida	C	111,901	1.011	1,131,830	1.037	1,160,924	29,094
	Non-Florida	C	97,300	1.738	1,691,060	1.764	1,716,358	25,298
Total			209,201	1.349	2,822,890	1.375	2,877,282	54,392
April 2000	Florida	C	92,996	2.268	2,109,220	2.368	2,202,216	92,996
	Non-Florida	C	97,268	1.937	1,884,050	2.037	1,981,318	97,268
Total			190,264	2.099	3,993,270	2.199	4,183,534	190,264
May 2000	Florida	C	104,732	2.138	2,239,310	2.163	2,265,493	26,183
	Non-Florida	C	108,817	1.849	2,012,030	1.874	2,039,234	27,204
Total			213,549	1.991	4,251,340	2.016	4,304,727	53,387
June 2000	Florida	C	100	2.300	2,300	2.325	2,325	25
	Non-Florida	C	0	0.000	0	0.000	0	0
Total			100	2.300	2,300	2.325	2,325	25

Date:8/3/99
Company: Florida Power & Light

Schedule: E9
Page : 2

Economy Energy Purchases

Estimated For the Period of : January 2000 Thru December 2000

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
July 2000	Florida	C	100	2.300	2,300	2.326	2,326	26
	Non-Florida	C	0	0.000	0	0.000	0	0
Total			100	2.300	2,300	2.326	2,326	26
August 2000	Florida	C	100	2.300	2,300	2.400	2,400	100
	Non-Florida	C	0	0.000	0	0.000	0	0
Total			100	2.300	2,300	2.400	2,400	100
September 2000	Florida	C	300	2.300	6,900	2.400	7,200	300
	Non-Florida	C	0	0.000	0	0.000	0	0
Total			300	2.300	6,900	2.400	7,200	300
October 2000	Florida	C	103,667	2.412	2,500,100	2.612	2,707,434	207,334
	Non-Florida	C	96,384	2.414	2,326,680	2.614	2,519,448	192,768
Total			200,051	2.413	4,826,780	2.613	5,226,882	400,102
November 2000	Florida	C	106,003	1.681	1,781,640	1.881	1,993,646	212,006
	Non-Florida	C	96,657	1.822	1,761,070	2.022	1,954,384	193,314
Total			202,660	1.748	3,542,710	1.948	3,948,030	405,320
December 2000	Florida	C	111,801	1.408	1,574,600	1.808	2,021,804	447,204
	Non-Florida	C	110,985	1.524	1,691,390	1.924	2,135,330	443,940
Total			222,786	1.466	3,265,990	1.866	4,157,134	891,144
Period Total	Florida	C	831,163	1.793	14,905,330	1.925	15,999,965	1,094,635
	Non-Florida	C	810,631	1.851	15,001,470	1.981	16,061,123	1,059,653
Total			1,641,794	1.822	29,906,800	1.953	32,061,088	2,154,288

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	APR 99 - DEC 99	JAN 00 - DEC 00	DIFFERENCE $	DIFFERENCE %
BASE	$43.26	$43.26	0	0.00%
FUEL	$19.80	$18.99	-0.81	-4.09%
CONSERVATION	$2.15	$1.89	-0.26	-12.09%
CAPACITY PAYMENT	$5.14	$4.77	-0.37	-7.20%
ENVIRONMENTAL	$0.22	$0.16	-0.06	-27.27%
SUBTOTAL	$70.57	$69.07	-1.50	-2.13%
GROSS RECEIPTS TAX	$0.72	$0.71	($0.01)	-1.39%
TOTAL	**$71.29**	**$69.78**	**($1.51)**	**-2.12%**

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL JAN - DEC 1997 - 1997 (COLUMN 1)	ACTUAL JAN - DEC 1998 - 1998 (COLUMN 2)	ESTIMATED/ACTUAL JAN - DEC 1999 - 1999 (COLUMN 3)	PROJECTED JAN - DEC 2000 - 2000 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	428,737,884	550,627,370	491,506,327	598,930,050	28.4	(10.7)	21.9
2	LIGHT OIL	1,636,840	8,740,433	10,885,249	12,508,530	434.0	24.5	14.9
3	COAL	115,294,193	101,816,412	97,992,172	107,376,380	(11.9)	(3.8)	9.6
4	GAS	683,748,049	585,674,627	532,810,266	542,954,210	(17.3)	(5.8)	1.9
5	NUCLEAR	85,010,563	83,172,087	79,816,030	71,943,110	(2.2)	(4.3)	(9.6)
6	OTHER (ORIMULSION)	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	1,314,427,569	1,309,832,928	1,212,810,048	1,333,714,280	(0.4)	(7.4)	10.0
	SYSTEM NET GENERATION							
8	HEAVY OIL	15,447,926	25,445,642	22,471,886	23,875,630	64.7	(11.7)	6.3
9	LIGHT OIL	25,385	155,996	226,756	240,707	514.5	45.4	6.2
10	COAL	6,903,083	6,434,035	6,338,207	7,018,483	(6.8)	(1.5)	10.7
11	GAS	25,530,174	23,486,341	22,018,562	20,391,448	(8.1)	(6.2)	(7.4)
12	NUCLEAR	22,000,214	24,305,259	24,216,422	23,082,272	10.5	(0.4)	(4.7)
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	69,906,762	79,807,278	75,271,853	74,606,540	14.2	(5.7)	(0.9)
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	24,876,031	40,586,472	35,642,744	37,686,619	63.2	(12.2)	5.7
16	LIGHT OIL (Bbl)	56,393	379,983	537,385	573,162	550.7	41.4	6.7
17	COAL (TON)	767,457	775,547	754,984	3,718,404	1.1	(2.7)	392.3
18	GAS (MCF)	218,129,792	195,289,551	183,614,092	164,188,889	(9.7)	(6.0)	(10.6)
19	NUCLEAR (MMBTU)	241,896,586	265,888,043	256,551,889	235,038,613	9.8	(3.4)	(8.4)
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	158,726,941	256,279,503	227,026,040	241,194,361	61.5	(11.4)	6.2
22	LIGHT OIL	339,356	2,211,174	3,119,298	3,328,104	551.6	41.1	6.6
23	COAL	86,723,547	61,998,143	62,731,530	71,076,425	(7.1)	1.2	13.3
24	GAS	225,122,265	204,338,659	187,526,577	164,188,889	(9.2)	(8.2)	(12.5)
25	NUCLEAR	241,896,586	265,888,043	256,551,901	235,038,613	9.8	(3.4)	(8.4)
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	692,808,695	790,515,522	736,957,346	714,824,172	14.1	(6.8)	(3.0)
	GENERATION MIX (%MWH)							
28	HEAVY OIL	22.10	31.88	29.85	32.00	-	-	-
29	LIGHT OIL	0.04	0.20	0.30	0.32	-	-	-
30	COAL	9.87	8.06	8.42	9.40			
31	GAS	36.52	29.40	29.25	27.33	-	-	-
32	NUCLEAR	31.47	30.45	32.17	30.94	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	17.2350	13.5668	13.7896	15.8924	(21.3)	1.6	15.3
36	LIGHT OIL ($/Bbl)	28.0314	23.0022	20.2556	21.8237	(17.9)	(11.9)	7.7
37	COAL ($/TON)	48.2793	32.9967	32.7814	28.8931	(31.7)	(0.7)	(11.8)
38	GAS ($/MCF)	3.1636	2.8969	2.9018	3.3089	(8.4)	0.2	14.0
39	NUCLEAR ($/MMBTU)	0.3514	0.3130	0.3103	0.3061	(10.9)	(0.9)	(1.4)
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	2.7011	2.1485	2.1650	2.4832	(20.5)	0.8	14.7
42	LIGHT OIL	4.8234	3.9528	3.4896	3.7607	(18.1)	(11.7)	7.8
43	COAL	1.7279	1.6391	1.5621	1.5107	(5.1)	(4.7)	(3.3)
44	GAS	3.0372	2.7883	2.8412	3.3089	(8.9)	2.8	16.4
45	NUCLEAR	0.3514	0.3130	0.3103	0.3061	(10.9)	(0.9)	(1.4)
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	1.8972	1.8589	1.8457	1.8858	(12.7)	(0.7)	13.4
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,275	10,072	10,103	10,102	(2.0)	0.3	(0.0)
49	LIGHT OIL	13,368	14,174	13,756	13,818	6.0	(3.0)	0.5
50	COAL	9,686	9,636	9,897	10,130	(0.5)	2.7	2.4
51	GAS	8,818	8,708	8,517	8,052	(1.3)	(2.2)	(5.5)
52	NUCLEAR	10,995	10,931	10,594	10,183	(0.6)	(3.1)	(3.9)
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	9,910	9,905	9,791	9,581	(0.1)	(1.2)	(2.1)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	2.7754	2.1639	2.1872	2.5085	(22.0)	1.1	14.7
56	LIGHT OIL	6.4481	5.6029	4.8004	5.1968	(13.1)	(14.3)	8.3
57	COAL	1.6702	1.5794	1.5461	1.5304	(5.4)	(2.1)	(1.0)
58	GAS	2.6782	2.4106	2.4196	2.6627	(10.0)	0.4	10.0
59	NUCLEAR	0.3864	0.3422	0.3288	0.3117	(11.4)	(3.9)	(5.2)
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	1.8803	1.8412	1.8112	1.7877	(12.7)	(1.8)	11.0

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next four semi-annual periods are as follows. In addition, As-Available Energy cost payments will include .0004¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2000 - March 31, 2000	2.21	2.09	2.12
April 1, 2000 - September 30, 2000	2.68	2.31	2.41
October 1, 2000 - March 31, 2001	2.37	2.24	2.27
April 1, 2001 - September 30, 2001	2.87	2.55	2.63
October 1, 2001 - December 31, 2001	2.69	2.46	2.52

A MW block size ranging from 24 MW to 36 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0265
Secondary Voltage Delivery	1.0585

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2000	25	31	22	8	15	.41	2.08	2.76	1.51
2001	24	26	26	7	17	.41	2.31	2.97	1.54
2002	24	20	32	7	17	.42	2.48	3.22	1.55
2003	23	11	45	6	15	.42	2.56	3.32	1.56
2004	23	12	44	6	15	.43	2.63	3.40	1.58
2005	23	12	44	6	15	.44	2.65	3.44	1.60
2006	22	12	46	6	14	.45	2.62	3.44	1.64
2007	22	12	48	5	13	.42	2.59	3.45	1.67
2008	22	10	50	5	13	.43	2.59	3.51	1.69
2009	21	12	49	6	13	.44	2.65	3.58	1.67

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	9.00	CST-1	110.00
GST-1	12.30	GSLD-2	170.00
GSD-1	35.00	GSLDT-2	170.00
GSDT-1	41.50	CS-2	170.00
RS-1	5.65	CST-2	170.00
RST-1	8.95	GSLD-3	400.00
GSLD-1	41.00	CS-3	400.00
GSLDT-1	41.00	CST-3	400.00
CS-1	110.00	GSLDT-3	400.00

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progresively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.218%
Distribution Equipment	0.352%
Transmission Equipment	0.144%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX I

FUEL COST RECOVERY

TRUE-UP CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 20
COMPANY/ WITNESS: Dubin
DATE: 11-22-99

KMD - 1
DOCKET NO. 990001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-4
APRIL 1, 1999

APPENDIX I

FUEL COST RECOVERY CLAUSE

TABLE OF CONTENTS

PAGE	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4	CALCULATION OF FINAL TRUE-UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998

1	End of Period True-up for the nine month period April through December 1998 (from page 4, lines D7 & D8)	$	(95,639,291)
2	Less - Estimated/Actual True-up for the same period *		(129,170,389)
3	Net True-up for the nine month period April through December 1998	$	33,531,098

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-98-1715-FOF-EI dated December 18, 1998

			FLORIDA POWER & LIGHT COMPANY				
			FUEL COST RECOVERY CLAUSE				
			CALCULATION OF FINAL TRUE-UP VARIANCES				
			NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998				
				(1)	(2)	(3)	(4)
	LINE				UPDATED	VARIANCE	
	NO.			ACTUAL	ESTIMATE (a)	AMOUNT	%
A	1	a	Fuel Cost of System Net Generation	$ 1,072,553,806	$ 1,030,560,149	$ 41,993,657	4.1 %
		b	Nuclear Fuel Disposal Costs	17,094,185	16,845,686	248,499	1.5 %
		c	Coal Cars Depreciation & Return	3,749,863	3,723,771	26,092	0.7 %
		d	Nuclear Thermal Uprate Amortization & Return	3,241,844	3,241,844	0	0.0 %
		e	Gas Pipelines Depreciation & Return	2,393,429	2,393,429	(0)	0.0 %
		f	DOE Decontamination & Decommissioning Fund Payment	5,435,701	5,586,000	(150,299)	(2.7) %
	2		Fuel Cost of Power Sold	(47,417,729)	(47,669,328)	251,599	(0.5) %
	3	a	Fuel Cost of Purchased Power	108,131,655	110,451,646	(2,319,991)	(2.1) %
		b	Energy Payments to Qualifying Facilities	85,487,693	98,156,848	(12,669,155)	(12.9) %
	4		Energy Cost of Economy Purchases	22,836,002	46,454,218	(23,618,216)	(50.8) %
	5		Total Fuel Costs & Net Power Transactions	$ 1,273,506,448	$ 1,269,744,262	$ 3,762,186	0.3 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (16,335,854)	$ (16,794,945)	$ 459,090	(2.7) %
		b	Reactive and Voltage Control Fuel Revenues	(432,301)	(232,451)	(199,850)	86.0 %
		c	Inventory Adjustments	180,394	190,120	(9,726)	N/A
		d	Non Recoverable Oil/Tank Bottoms	(8,018)	211,198	(219,216)	(103.8) %
		e	Modifications to Burn Low Gravity Oil	1,975,051	1,375,634	599,417	43.6 %
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 1,258,885,721	$ 1,254,493,818	$ 4,391,903	0.4 %
C	1		Jurisdictional kWh Sales	67,127,103,384	65,204,627,493	1,922,475,891	2.9 %
	2		Sale for Resale	350,577,713	343,106,944	7,470,769	2.2 %
	3		Total Sales (Excluding RTP Incremental)	67,477,681,097	65,547,734,437	1,929,946,660	2.9 %
	4			N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 1,301,516,289	$ 1,263,943,770	$ 37,572,519	3.0 %
		a	Prior Period True-up Provision	(135,509,164)	(135,509,164)	0	0.0 %
		b	GPIF, Net of Revenue Taxes (b)	(2,855,039)	(2,855,039)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes	(126)	(150)	24	(16.1) %
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 1,163,151,960	$ 1,125,579,418	$ 37,572,543	3.3 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 1,258,885,721	$ 1,254,493,818	$ 4,391,903	0.4 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	830,083	542,109	287,973	53.1 %
		d	D&D Fund Payments -100% Retail	5,435,701	0	5,435,701	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	1,252,619,936	1,253,951,709	4,103,929	0.3 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 1,253,287,887	$ 1,248,885,777	$ 4,402,110	0.4 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (90,135,927)	$ (123,306,360)	$ 33,170,433	(26.9) %
	8		Interest Provision for the Month	(5,503,364)	(5,864,029)	360,665	(6.2) %
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(135,509,164)	(135,509,164)	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	13,491,202	13,491,202	0	0.0 %
	10		Prior Period True-up Collected/(Refunded) This Period	135,509,164	135,509,164	(0)	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (82,148,089)	$ (115,679,187)	$ 33,531,098	(29.0) %
NOTES		(a)	**Per Schedule E-1b, filed October 5, 1998.**				
		(b)	**Generation Performance Incentive Factor is (($5,801,940 / 2) / 9) x 98.4167%) - See Order Nos. PSC-97-1045-FOF-EI & PSC-98-0412-FOF-EI.**				

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO 990001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-6
APRIL 1, 1999

APPENDIX II
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION
3	SUMMARY OF NET TRUE-UP AMOUNT
4	CALCULATION OF FINAL TRUE-UP AMOUNT
5	CALCULATION OF INTEREST PROVISION
6	CALCULATION OF FINAL TRUE-UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP AMOUNT FOR THE
NINE MONTH PERIOD APRIL THROUGH DECEMBER 1998

1.	True-up Amount for the nine month period ended December 31, 1998	$ 70,611,128
2.	Less: Estimated/Actual Over/(Under) Recovery for the same nine month period (a)	65,406,291
3.	Net True-up: Over/(Under) Recovery to be carried forward to the January through December 2000 period	$5,204,837

Notes: (a) Approved in FPSC Order No. PSC-98-1715-FOF-EI dated December 18, 1998.

( ) Denotes an underrecovery

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH DECEMBER 1998

LINE NO.		(1) APR 1998	(2) MAY 1998	(3) JUN 1998	(4) JUL 1998	(5) AUG 1998	(6) SEP 1998	(7) OCT 1998	(8) NOV 1998	(9) DEC 1998	(10) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 11,740,754	$ 9,944,103	$ 9,940,061	$ 1,171,874	$ 8,342,282	$ 10,014,980	$ 9,737,851	$ 9,740,305	$ 9,786,006	$ 80,418,216	1.
2.	JEA/UPS Capacity Charges	-	-	-	-	-	-	-	-	-	-	2.
3.	QF Capacity Charges	24,953,830	24,885,138	24,931,411	25,161,758	24,977,643	24,936,518	24,934,246	24,915,329	24,906,527	224,602,401	3.
4.	SJRPP Capacity Charges	7,332,267	7,317,575	6,809,525	7,111,523	6,956,174	7,418,693	6,818,859	6,601,346	6,137,867	62,503,830	4.
4a.	SJRPP Suspension Accrual	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	391,667	3,525,000	4a.
4b.	Return Requirements on SJRPP Suspension Liability	(26,271)	(30,312)	(34,354)	(38,396)	(42,437)	(46,479)	(50,521)	(54,562)	(58,604)	(381,936)	4b.
5.	SJRPP Deferred Interest Payment	56,435	56,435	56,435	56,435	388,028	388,028	(62,888)	(62,888)	(62,888)	813,133	5.
6.	Cypress Settlement (Capacity)	1,530,589	-	-	-	-	-	1,530,589	-	148,450	3,209,628	6.
7.	Transmission of Electricity by Others - FPL Sales	143,986	447,468	30,446	238,364	61,745	201,610	16,200	2,438	60,909	1,203,165	7.
8.	Revenues from Capacity Sales	(735,948)	(11,618,781)	(23,692,850)	(16,581,063)	(6,992,235)	(5,371,137)	(738,145)	(398,284)	(1,281,622)	(67,410,065)	8.
9.	Total (Lines 1 through 8)	$ 45,387,310	$ 31,393,293	$ 18,432,341	$ 17,512,162	$ 34,082,866	$ 37,933,881	$ 42,577,858	$ 41,135,350	$ 40,028,312	$ 308,483,372	9.
10.	Jurisdictional Separation Factor (a)	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	97.19921%	N/A	10.
11.	Jurisdictional Capacity Charges	44,116,107	30,514,033	17,916,090	17,021,683	33,128,277	36,871,432	41,385,342	39,983,235	38,907,203	299,843,401	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(42,709,194)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 39,370,641	$ 25,768,567	$ 13,170,624	$ 12,276,217	$ 28,382,811	$ 32,125,966	$ 36,639,876	$ 35,237,769	$ 34,161,737	$ 257,134,207	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 25,835,592	$ 26,090,144	$ 32,242,608	$ 34,852,559	$ 33,664,909	$ 33,739,517	$ 32,198,129	$ 28,503,261	$ 26,726,799	$ 273,853,518	14.
15.	Prior Period True-up Provision	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	5,631,576	50,684,184	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 31,467,168	$ 31,721,720	$ 37,874,184	$ 40,484,135	$ 39,296,485	$ 39,371,093	$ 37,829,705	$ 34,134,837	$ 32,358,375	$ 324,537,702	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(7,903,472)	5,953,153	24,703,560	28,207,918	10,913,675	7,245,126	1,189,829	(1,102,932)	(1,803,362)	67,403,495	17.
18.	Interest Provision for Month	255,933	226,746	274,082	373,670	437,023	440,997	419,567	408,123	371,491	3,207,632	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	50,684,185	37,405,071	37,953,394	57,299,460	80,249,472	85,968,593	88,023,141	84,000,961	77,674,576	50,684,185	19.
20.	Deferred True-up - Over/(Under) Recovery	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	11,771,496	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(5,631,576)	(50,684,184)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 49,176,566	$ 49,724,889	$ 69,070,955	$ 92,020,967	$ 97,740,089	$ 99,794,637	$ 95,772,457	$ 89,446,072	$ 82,382,625	$ 82,382,625	22.

Notes:
(a) Per K. M. Dubin's Testimony Appendix IV, Page 3, Docket No. 980001-EI, filed January 12, 1998
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD APRIL THROUGH DECEMBER 1998

LINE NO.		(1) APR 1998	(2) MAY 1998	(3) JUN 1998	(4) JUL 1998	(5) AUG 1998	(6) SEP 1998	(7) OCT 1998	(8) NOV 1998	(9) DEC 1998	(10) TOTAL	LINE NO.
1.	Beginning True-up Amount	$62,455,681	$49,176,566	$49,724,889	$69,070,955	$92,020,967	$97,740,089	$99,794,637	$95,772,457	$89,446,072	n/a	1.
2.	Ending True-up Amount Before Interest	48,920,633	49,498,143	68,796,874	91,647,297	97,303,066	99,353,639	95,352,890	89,037,949	82,011,134	n/a	2.
3.	Total Beginning & Ending True-up Amount (Lines 1+2)	111,376,314	98,674,709	118,521,763	160,718,253	189,324,033	197,093,728	195,147,526	184,810,406	171,457,206	n/a	3.
4.	Average True-up Amount (50 % of Line 3)	$55,688,157	$49,337,355	$59,260,882	$80,359,126	$94,662,017	$98,546,864	$97,573,763	$92,405,203	$85,728,603	n/a	4.
5.	Interest Rate - First day of Reporting Business Month	5.50000%	5.53000%	5.50000%	5.60000%	5.56000%	5.52000%	5.22000%	5.10000%	5.50000%	n/a	5.
6.	Interest Rate - First day of Subsequent Business Month	5.53000%	5.50000%	5.60000%	5.56000%	5.52000%	5.22000%	5.10000%	5.50000%	4.90000%	n/a	6.
7.	Total Interest Rate (Lines 5+6)	11.03000%	11.03000%	11.10000%	11.16000%	11.08000%	10.74000%	10.32000%	10.60000%	10.40000%	n/a	7.
8.	Average Interest Rate (50 % of Line 7)	5.51500%	5.51500%	5.55000%	5.58000%	5.54000%	5.37000%	5.16000%	5.30000%	5.20000%	n/a	8.
9.	Monthly Average Interest Rate (1/12 of Line 8)	0.45958%	0.45958%	0.46250%	0.46500%	0.46167%	0.44750%	0.43000%	0.44167%	0.43333%	n/a	9.
10.	Interest Provision for the Month (Line 4 X Line 9)	$255,933	$226,746	$274,082	$373,670	$437,023	$440,997	$419,567	$408,123	$371,491	$2,008,451	10.

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE NINE MONTH PERIOD APRIL 1998 THROUGH DECEMBER 1998

		(1)	(2)	(3)	(4)
			ESTIMATED /		PERCENTAGE
		ACTUAL	ACTUAL (a)	VARIANCE	CHANGE
1.	Payments to Non-cogenerators	$ 143,735,179	$ 159,114,020	$ (15,378,841)	-9.7%
2	Payments to Cogenerators	224,602,401	229,349,168	(4,746,767)	-2.1%
3.	SJRPP Suspension Accrual	3,525,000	3,525,003	(3)	N/A
4.	Return Requirements on SJRPP Suspension Liability	(381,936)	(381,936)	0	N/A
4b.	Cypress Settlement (Capacity)	3,209,628	1,530,589	1,679,039	109.7%
5.	Transmission of Electricity by Others - FPL Sales	1,203,165	922,009	281,156	30.5%
6.	Revenues from Capacity Sales	(67,410,065)	(87,720,877)	20,310,812	-23.2%
7.	Total (Lines 1 through 6)	$ 308,483,372	$ 306,337,976	$ 2,145,396	0.7%
8.	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
9.	Jurisdictional Capacity Charges	$ 299,843,401	$ 297,758,092	$ 2,085,309	0.7%
10.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (42,709,194)	(42,709,194)	0	N/A
11.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 257,134,207	$ 255,048,898	$ 2,085,309	0.8%
12.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 273,853,518	$ 266,527,861	$ 7,325,657	2.7%
13.	Prior Period True-up Provision	50,684,184	50,684,184	0	N/A
14.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 324,537,702	$ 317,212,045	$ 7,325,657	2.3%
15.	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 67,403,495	$ 62,163,147	$ 5,240,348	N/A
16.	Interest Provision for Period	3,207,632	3,243,144	(35,512)	N/A
17.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	50,684,185	50,684,185	0	N/A
18.	Deferred True-up - Over/(Under) Recovery	11,771,496	11,771,496	0	N/A
19.	Prior Period True-up Provision - Collected/(Refunded) this Period	(50,684,185)	(50,684,185)	0	N/A
20.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 82,382,624	$ 77,177,787	$ 5,204,837	N/A

Notes:
(a) Per K. M. Dubin's Testimony Appendix III, Page 7, Docket No. 980001-EI, filed October 5, 1998.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS JANUARY THROUGH DECEMBER 2000

PART A - SALES FORECAST ASSUMPTIONS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 21
COMPANY/ WITNESS: Wieland
DATE: 11-22-99

SALES FORECAST ASSUMPTIONS

1. This five-year forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for budgeting and financial planning purposes. This forecast was prepared in June 1999.

2. Normal weather conditions are assumed. For kilowatt-hour sales projections, normal weather is based on a historical ten-year average of service area weighted billing month degree days. Seasonal peak demand projections are based on a twenty year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provide the basis for development of the customer forecast. This forecast incorporates "Population Studies", Bulletin No. 123 (February 1999) as well as THE FLORIDA LONG-TERM ECONOMIC OUTLOOK, 1998. Other statewide economic statistics developed by the Florida Economic Estimating Conference (February 1999) were incorporated as were national economic projections produced by Standard & Poor's DRI, Incorporated.

4. FPC's energy intensive phosphate mining customers consumed over 35% of total industrial class energy sales in 1998. The FPC service area currently has six major producers with either national and/or international influence upon the supply of phosphate-based fertilizers. Load and energy consumption at the FPC-served mining or chemical pricing sites depend heavily on plant operations which are influenced by both micro- and macroeconomic conditions. There is presently excess mining capacity in the State, due tp weak farm commodity prices worldwide. Weak farm prices lead to lower crop production. This results in less demand for fertilizer products. In addition,

two of FPC's phosphate mining customers are contemplating self-generation or transmission investment that adds greater uncertainty to projections of demand of energy for this customer group. The most-likely scenario for energy consumption based on the above considerations has been developed and is expected to result in lower energy usage going forward.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on a full, partial and supplemental requirements basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by FPC as of May 31, 1999. The forecast of energy and demand to the partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from the Florida broker system any time it is more economical for them to do so. FPC's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve supplemental service over and above stated self-service level of 1,218 MW in 2000. SECI's projection of their system's supplemental demand and energy requirements has been incorporated into this forecast. This forecast also assumes that all expiring municipal franchise agreements will be renewed.

   This forecast also includes five wholesale bulk power contracts. The first is a multi-part power contract with SECI to serve 605 MW for three years beginning in 1999 and ending in 2001. An option to extend one piece of this contract (150 MW) has been exercised by SECI and incorporated into the forecast. A second three year agreement with SECI to sell up to 300 MW of peaking power beginning in 2000 has also been reflected in the forecast.

6. This forecast incorporates demand and energy reductions from FPC'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

7. Expected energy and demand reductions from self-service cogeneration are included in this forecast. FPC will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. The economic outlook for this forecast calls for moderating economic growth. No "shocks" to any supply or demand conditions in the national economy are expected and thus no economic recession is incorporated in this forecast. The performance of the U.S. national economy since the early 1990s has exceeded all expectations. The current stretch of economic expansion has recently become the longest lasting peacetime economic expansion in U.S. history and is expected to become the longest expansion of any kind in February 2000. An appropriate mixture of fiscal and monetary policy actions on the part of the government economic officials has led to a boost in living standards without raising inflation or government deficit spending. Rising real incomes, the meteoric rise in the U.S. equity market, and unemployment rates at 30 year lows have all led to greater spending power for the American consumer and a high level of economic optimism. Looking ahead however, growth is expected to slow from that recently experienced. The Federal Reserve Board (FRB) has announced its willingness to lean toward policies that would restrain greater inflationary pressures. This could result in the application of tighter monetary policy, which would mean higher interest rates. This would result in higher borrowing costs for producers, consumers and home buyers and lead to slower economic growth.

On a regional basis, interest rate levels will continue to influence the pace of economic growth in Florida through their impacts on the construction, retirement and tourism industries. Personal income growth is expected to continue growing but not at the torrid pace experienced in recent years. Employment growth will moderate from the strong pace experienced in past years resulting in slower growth in total wages. Slower growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead. Export related job growth has room for improvement as the state of Latin America economies improve. Florida has developed significant trade relations with Central and South America and continues to attract a significant number of tourists from this area to Florida theme parks.

Growth in energy consumption is closely tied to the level of economic activity in the State as well as nationally and internationally. The state's business climate is viewed as improving. The level of taxation has been rolled back. The current job market is very strong and consumption reflects this. Average kWh use per residential customer will continue to grow as electricity prices are projected to decline in real dollar terms. Also contributing to this trend are homebuilders' surveys reporting increased median square footage in new homes and new apartments constructed. Increasing electric appliance saturation rates also serve to boost average electric use per customer.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS JANUARY THROUGH DECEMBER 2000

PART B - FUEL PRICE FORECAST ASSUMPTIONS

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and spot market purchases for 1999 & 2000.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA forecasts and current market information.

Transportation to the Tampa Bay area plus applicable environment taxes were added to the above prices (an adjustment was later made to transportation costs for individual plant locations when purchased from locations other than Tampa Bay).

B. Coal

Coal price projections are provided by Electric Fuels Corporation and represent an estimate of EFC's price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which EFC has or expects to have in place during 1999 & 2000 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of normal weather, no material changes in energy markets, governmental rule changes, etc. Prices are based on expected contract structures and spot market purchases for 1999 & 2000. Gas supply prices were derived from PIRA, NYMEX and current spot market information.

Transportation costs for Florida Gas Transmission pipeline firm transportation service is based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS JANUARY THROUGH DECEMBER 2000

PART C - FUEL PRICE FORECAST

Florida Power Corporation
Docket No. 990001-EI
Witness: K. H. Wieland
Exhibit No. _____
Part C
Sheet 1 of 4

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu's[1]	$/barrel	$/MMBtu[1]
Sept 1999	17.55	2.70	17.23	2.65	16.58	2.55
Oct 1999	17.55	2.70	17.23	2.65	16.58	2.55
Nov 1999	18.20	2.80	17.88	2.75	16.90	2.60
Dec 1999	18.20	2.80	17.88	2.75	16.90	2.60
Jan 2000	18.20	2.80	17.88	2.75	16.90	2.60
Feb 2000	18.20	2.80	17.88	2.75	16.90	2.60
Mar 2000	18.20	2.80	17.88	2.75	16.90	2.60
Apr 2000	16.25	2.50	15.93	2.45	14.95	2.30
May 2000	16.25	2.50	15.93	2.45	14.95	2.30
Jun 2000	16.25	2.50	15.93	2.45	14.95	2.30
Jul 2000	16.25	2.50	15.93	2.45	14.95	2.30
Aug 2000	16.25	2.50	15.93	2.45	14.95	2.30
Sep 2000	16.25	2.50	15.93	2.45	14.95	2.30
Oct 2000	18.20	2.80	17.88	2.75	16.90	2.60
Nov 2000	18.20	2.80	17.88	2.75	16.90	2.60
Dec2000	18.20	2.80	17.88	2.75	16.90	2.60

(1) 6.5 million BTU/barrel

Florida Power Corporation
Docket No. 990001-EI
Witness: K. H. Wieland
Exhibit No. _____
Part C
Sheet 2 of 4

FUEL PRICE FORECAST

#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu's[1]
Sep 1999	24.36	58.0	4.20
Oct 1999	24.36	58.0	4.20
Nov 1999	26.68	63.5	4.60
Dec 1999	26.68	63.5	4.60
Jan 2000	26.68	63.5	4.60
Feb 2000	26.68	63.5	4.60
Mar 2000	26.68	63.5	4.60
Apr 2000	24.36	58.0	4.20
May 2000	24.36	58.0	4.20
Jun 2000	24.36	58.0	4.20
Jul 2000	24.36	58.0	4.20
Aug 2000	24.36	58.0	4.20
Sep 2000	24.36	58.0	4.20
Oct 2000	26.68	63.5	4.60
Nov 2000	26.68	63.5	4.60
Dec 2000	26.68	63.5	4.60

(1) 5.8 million BTU/barrel & 42 gallons/barrel

Florida Power Corporation
Docket No. 980001-EI
Witness: K. H. Wieland
Exhibit No. _____
Part C
Sheet 3 of 4

FUEL PRICE FORECAST

Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
Jan 1998	12,689	41.89	1.650	12,512	49.71	1.986
Feb 1998	12,689	41.84	1.649	12,512	49.70	1.986
Mar 1998	12,689	41.89	1.651	12,513	49.66	1.984
Apr 1998	12,689	42.09	1.659	12,513	50.13	2.003
May 1998	12,695	41.78	1.646	12,513	49.35	1.972
Jun 1998	12,680	41.92	1.653	12,507	50.22	2.008
Jul 1998	12,694	42.02	1.655	12513	49.48	1.977
Aug 1998	12,676	42.25	1.666	12,507	50.27	2.010
Sep 1998	12,694	42.07	1.657	12,513	49.38	1.973

Florida Power Corporation
Docket No. 990001-EI
Witness: K. H. Wieland
Exhibit No. _____
Part C
Sheet 4 of 4

FUEL PRICE FORECAST

Natural Gas Supply

	INTO FLORIDA GAS TRANSMISSION [1]
Month	$/MMBtu
Sep 1999	2.74
Oct 1999	2.76
Nov 1999	2.85
Dec 1999	2.95
Jan 2000	2.96
Feb 2000	2.82
Mar 2000	2.65
Apr 2000	2.47
May 2000	2.40
Jun 2000	2.40
Jul 2000	2.38
Aug 2000	2.40
Sep 2000	2.41
Oct 2000	2.44
Nov 2000	2.57
Dec 2000	2.70

[1] Transport cost not included

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED CAPACITY COST FACTORS
JANUARY THROUGH DECEMBER 2000

PART D - CAPACITY COST RECOVERY CALCULATIONS

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Year 2000

Florida Power Corporation
Docket 990001-EI
Witness: K. H. Wieland
Exhibit No.
Part D
Sheet 1 of 5

	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
Base Production Level Capacity Charges:													
1 Payments to Qualifying Facilities	22,669,046	22,669,046	22,669,046	22,337,013	22,687,013	22,687,013	22,687,013	22,687,013	22,687,013	22,687,013	22,687,013	22,687,013	271,840,255
2 UPS Purchase (409 MW)	4,009,000	3,751,000	4,009,000	3,880,000	4,009,000	3,880,000	4,009,000	4,009,000	3,880,000	4,009,000	3,880,000	4,009,000	47,334,000
3 Other Power Sales	(222,087)	(939,934)	(589,428)	(120,676)	(214,083)	(1,292,314)	(2,553,672)	(2,564,978)	(1,000,554)	(535,927)	(204,938)	(289,902)	(10,528,493)
4 Subtotal - Base Level Capacity Charges	26,455,959	25,480,112	26,088,618	26,096,337	26,481,930	25,274,699	24,142,341	24,131,035	25,566,459	26,160,086	26,362,075	26,406,111	308,645,762
5 Base Production Jurisdictional %	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	
6 Base Jurisdictional Capacity Charges	25,541,378	24,599,265	25,186,734	25,194,187	25,566,450	24,400,953	23,307,740	23,296,825	24,682,627	25,255,732	25,450,738	25,493,252	297,975,876
Intermediate Production Level Capacity Charges:													
7 TECO Power Purchase	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	6,808,404
8 Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Subtotal - Intermediate Level Capacity Charges	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	567,367	6,808,404
10 Intermediate Production Jurisdictional %	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	
11 Intermediate Jurisdictional Capacity Charges	395,353	395,353	395,353	395,353	395,353	395,353	395,353	395,353	395,353	395,353	395,353	395,353	4,744,232
Peaking Production Level Capacity Charges:													
12 Peaking Purchases - Yearly	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	180,000	2,160,000
13 Peaking Purchases - Summer Peak	0	0	0	0	0	2,800,000	2,800,000	2,800,000	800,000	0	0	0	9,200,000
14 Peaking Purchases - Winter Peak	450,000	450,000	0	0	0	0	0	0	0	0	0	450,000	1,350,000
15 Subtotal - Peaking Level Capacity Charges	630,000	630,000	180,000	180,000	180,000	2,980,000	2,980,000	2,980,000	980,000	180,000	180,000	630,000	12,710,000
16 Peaking Production Jurisdictional %	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	
17 Peaking Jurisdictional Capacity Charges	466,282	466,282	133,223	133,223	133,223	2,205,587	2,205,587	2,205,587	725,327	133,223	133,223	466,282	9,407,052
18 Sebring Base Rate Credits	(345,220)	(337,738)	(315,359)	(318,142)	(324,587)	(386,519)	(429,537)	(424,076)	(439,071)	(380,253)	(319,042)	(324,680)	(4,344,224)
19 Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18)	26,057,791	25,123,161	25,399,952	25,404,621	25,770,439	26,615,374	25,479,143	25,473,689	25,364,236	25,404,055	25,660,272	26,030,206	307,782,936
20 Estimated/Actual True-Up Provision for the *Period January through December 1999*													(33,314,649)
21 Total (Sum of lines 19 & 20)													274,468,289
22 Revenue Tax Multiplier													1.00072
23 *Total Recoverable Capacity Payments*													274,665,906

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 1999

Florida Power Corporation
Docket 990001-EI
Witness K H Wieland
Exhibit No
Part D
Sheet 2 of 5

		Actual Jan-99	Actual Feb-99	Actual Mar-99	Actual Apr-99	Actual May-99	Actual Jun-99	Actual Jul-99	Actual Aug-99	Estimated Sep-99	Estimated Oct-99	Estimated Nov-99	Estimated Dec-99	Total
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	21,670,672	21,701,614	21,597,774	21,377,439	21,874,213	21,721,920	21,520,823	21,703,649	22,260,539	22,260,539	21,612,539	21,591,539	260,893,261
2	UPS Purchase (409 MW)	4,410,441	4,233,735	4,259,965	3,877,759	3,900,379	4,160,986	2,181,709	3,874,909	4,240,000	4,381,000	4,240,000	4,381,000	48,141,884
3	Other Power Sales	(309,924)	(873,871)	(815,382)	807,545	(399,353)	(3,046,958)	(7,482,781)	(1,350,205)	(1,539,442)	(102,212)	(83,564)	(156,436)	(15,352,583)
4	*Subtotal - Base Level Capacity Charges*	25,771,189	25,061,478	25,042,357	26,062,743	25,375,239	22,835,948	16,219,751	24,228,353	24,961,097	26,539,327	25,768,975	25,816,103	293,682,566
5	Base Production Jurisdictional %	96.110%	96.110%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	96.543%	
6	Base Level Jurisdictional Capacity Charges	24,768,690	24,086,587	24,176,643	25,161,754	24,498,017	22,046,509	15,659,034	23,390,779	24,098,192	25,621,862	24,878,142	24,923,640	283,309,848
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	6,786,804
8	Other Power Sales	(2,662)	(2,404)	(2,662)	(2,576)	(2,385)	0	50,904	(4,692)	0	0	0	0	33,523
9	Subtotal - Intermediate Level Capacity Charges	562,905	563,163	562,905	562,991	563,182	565,567	616,471	560,875	565,567	565,567	565,567	565,567	6,820,327
10	Intermediate Production Jurisdictional %	73.773%	73.773%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	69.682%	
11	Intermediate Level Jurisdictional Capacity Charges	415,272	415,462	392,243	392,303	392,436	394,098	429,569	390,829	394,098	394,098	394,098	394,098	4,798,606
	Peaking Production Level Capacity Charges:													
12	Peaking Purchases - Yearly	0	0	0	0	0	0	0	0	0	0	180,000	180,000	360,000
13	Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Peaking Purchases - Winter Peak	0	0	0	0	0	0	0	0	0	0	0	450,000	450,000
15	Subtotal - Peaking Level Capacity Charges	0	0	0	0	0	0	0	0	0	0	180,000	630,000	810,000
16	Peaking Production Jurisdictional %	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	74.013%	
17	Peaking Level Jurisdictional Capacity Charges	0	0	0	0	0	0	0	0	0	0	133,223	466,282	599,505
18	Adjustments - Premium	0	0	0	0	0	0	0	(2,027,403)	(500,000)	0	0	0	(2,527,403)
19	Sebring Base Rate Credits	(356,323)	(273,476)	(321,391)	(319,764)	(316,979)	(339,077)	(373,108)	(421,342)	(390,587)	(361,367)	(315,622)	(328,278)	(4,117,316)
20	Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18 + 19)	24,827,639	24,228,573	24,247,495	25,234,293	24,573,474	22,101,531	15,715,496	21,332,863	23,601,703	25,654,594	25,089,841	25,455,743	282,063,244
21	Capacity Cost Recovery Revenues	24,431,758	20,875,222	21,484,013	22,856,709	24,403,091	27,388,256	30,049,391	34,626,187	31,326,880	28,390,286	24,347,674	24,447,878	314,625,345
22	Prior Period True-Up Provision	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,726)	(404,728)	(4,856,714)
23	Current Period Capacity Revenues (Lines 21+22)	24,027,032	20,470,496	21,079,287	22,451,983	23,998,365	26,981,530	29,644,665	34,221,461	30,922,154	27,985,560	23,942,948	24,043,150	309,768,631
24	Current Period Over/(Under) Recovery (Lines 23-20)	(800,607)	(3,758,077)	(3,168,208)	(2,782,310)	(575,109)	4,879,999	13,929,169	12,888,598	7,320,451	2,330,966	(1,146,893)	(1,412,593)	27,705,387
25	Interest Provision for Month	98	(7,457)	(19,911)	(30,252)	(35,420)	(25,974)	14,746	75,007	120,836	144,007	148,947	145,803	530,431
26	Current Cycle Balance	(800,509)	(4,566,042)	(7,754,161)	(10,566,723)	(11,177,253)	(6,323,227)	7,620,688	20,584,292	28,025,580	30,500,553	29,502,607	28,235,817	28,235,817
27	Plus: Prior Period Balance	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118	222,118
28	Plus: Cumulative True-Up Provision	404,726	809,452	1,214,178	1,618,904	2,023,630	2,428,356	2,833,082	3,237,808	3,642,534	4,047,260	4,451,986	4,856,714	4,856,714
29	End of Period Net True-Up (Line 26+27+28)	(173,665)	(3,534,472)	(6,317,865)	(8,725,701)	(8,931,505)	(3,672,753)	10,675,888	24,044,218	31,890,232	34,769,931	34,176,711	33,314,649	33,314,649

Florida Power Corporation
Docket 990001-EI
Witness: K. H. Wieland
Exhibit No. _____
Part D
Sheet 3 of 5

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 1998 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	591,561	1,139	592,700		0.9790000	605,414		
2. Distribution Primary	4,815,638	9,270	4,824,908		0.9690000	4,979,265		
3. Distribution Secondary	27,979,413	53,863	28,033,276		0.9458216	29,639,074		
Total Retail	33,386,612	64,272	33,450,884	93.68%	0.9496684	35,223,753	93.92%	1.0026
B. WHOLESALE								
1. Source Level	1,395,119	(39,920)	1,355,199		1.0000000	1,355,199		
2. Transmission	798,682	(1,391)	797,291		0.9790000	814,393		
3. Distribution Primary	106,040	8	106,048		0.9690000	109,441		
4. Distribution Secondary	0	0	0		0.9458216	0		
Total Wholesale	2,299,841	(41,303)	2,258,538	6.32%	0.9910070	2,279,033	6.08%	0.9608
Total Class Loads	35,686,453	22,969	35,709,422	100.00%	0.9521805	37,502,786	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	176,491	0	176,491		0.9458216	186,601		
2. Seminole Electric	0	0	0		1.0000000	0		
3. Kissimmee	0	0	0		0.9790000	0		
4. St. Cloud	0	0	0		0.9790000	0		
5. Interchange	1,524,750	0	1,524,750		0.9790000	1,557,457		
6. SEPA	39,874	0	39,874		0.9790000	40,729		
Total Non-Class Loads	1,741,115	0	1,741,115		0.9755310	1,784,787		
Total System	37,427,568	22,969	37,450,537		0.9532413	39,287,573		

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND
For the Year 2000

Rate Class	(1) Mwh Sales @ Meter Level	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/8760hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) Mwh Sales @ Meter Level	(7) Delivery Efficiency Factor	(8) Source Level Mwh (6)/(7)	(9) Annual Average Demand (8)/8760hrs
I. Residential Service	17,044,580	0.515	3,778.11	0.9458216	3,994.53	17,044,580	0.9458216	18,020,925	2,057.18
II. General Service Non-Demand									
Transmission	0	0.622	0.00	0.9790000	0.00	0	0.9790000	0	0.00
Primary	7,604	0.622	1.40	0.9690000	1.44	7,604	0.9690000	7,847	0.90
Secondary	1,189,926	0.622	218.39	0.9458216	230.90	1,189,926	0.9458216	1,258,087	143.62
Total Gen Serv Non-Demand	1,197,530		219.79		232.34	1,197,530		1,265,934	144.52
III. GS - 100% L.F.	64,719	1.000	7.39	0.9458216	7.81	64,719	0.9458216	68,426	7.81
IV. General Service Demand									
SS-1 - Transmission	9,453	1.218	0.89			9,453			
GSD-1 - Transmission	3,803	0.807	0.54			3,803			
Total Transmission	13,256		1.43	0.9790000	1.46	13,256	0.9790000	13,540	1.55
SS-1 - Primary	0	1.218	0.00			0			
GSD-1 - Primary	2,599,577	0.807	367.73			2,599,577			
Total Primary	2,599,577		367.73	0.9690000	379.49	2,599,577	0.9690000	2,682,742	306.25
GSD - Secondary	10,511,224	0.807	1,486.88	0.9458216	1,572.05	10,511,224	0.9458216	11,113,326	1,268.64
Total Gen Serv Demand	13,124,057		1,856.04		1,953.00	13,124,057		13,809,608	1,576.44
V. Curtailable Service									
CS - Primary	192,411	0.966	22.74			192,411			
SS-3 - Primary	3,027	1.039	0.33			3,027			
Total Primary	195,438		23.07	0.9690000	23.81	195,438	0.9690000	201,690	23.02
CS - Secondary	417	0.966	0.05	0.9458216	0.05	417	0.9458216	441	0.05
Total Curtailable Service	195,855		23.12		23.86	195,855		202,131	23.07
VI. Interruptible Service									
IS - Transmission	419,223	1.044	45.84			419,223			
SS-2 - Transmission	137,960	1.044	15.09			137,960			
Total Transmission	557,183		60.93	0.9790000	62.24	557,183	0.9790000	569,135	64.97
IS - Primary	1,994,497	1.044	218.09			1,994,497			
SS-2 - Primary	44,331	1.044	4.85			44,331			
Total Primary	2,038,828		222.94	0.9690000	230.07	2,038,828	0.9690000	2,104,054	240.19
IS - Secondary	85,524	1.044	9.35	0.9458216	9.89	85,524	0.9458216	90,423	10.32
Total Interruptible Service	2,681,535		293.22		302.20	2,681,535		2,763,612	315.48
VII. Lighting Service	250,330	3.779	7.56	0.9458216	7.99	250,330	0.9458216	264,669	30.21
Total Retail	**34,558,606**				**6,521.73**	**34,558,606**		**36,395,305**	**4,154.71**

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Year 2000

Florida Power Corporation
Docket 990001-EI
Witness: K. H. Wieland
Exhibit No.
Part D
Sheet 5 of 5

	(1) Average 12 CP Demand Mw	(2) Average 12 CP Demand %	(3) Annual Average Demand Mw	(4) Annual Average Demand %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Annual Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * Total	(9) Effective Mwh's @ Secondary Level Year 2000	(10) Capacity Cost Recovery Factor (c/Kwh)
I. Residential Service	3,994.53	61.249%	2,057.18	49.514%	56.537%	3.809%	60.346%	165,749,888	17,044,580	0.972
II. General Service Non-Demand										
Transmission									0	0.800
Primary									7,528	0.808
Secondary									1,189,926	0.816
Total Gen Serv Non-Demand	232.34	3.563%	144.52	3.479%	3.289%	0.268%	3.557%	9,769,866	1,197,454	
III. GS - 100% L.F.	7.81	0.120%	7.81	0.188%	0.111%	0.014%	0.125%	343,332	64,719	0.530
IV. General Service Demand										
Transmission									12,991	0.628
Primary									2,573,581	0.634
Secondary									10,511,224	0.641
Total Gen Service Demand	1,953.00	29.946%	1,576.44	37.944%	27.642%	2.919%	30.561%	83,940,648	13,097,796	
V. Curtailable Service										
Transmission									0	0.529
Primary									193,484	0.534
Secondary									417	0.540
Total Curtailable Service	23.86	0.366%	23.07	0.555%	0.338%	0.043%	0.381%	1,046,477	193,901	
VI. Interruptible Service										
Transmission									546,039	0.494
Primary									2,018,441	0.499
Secondary									85,524	0.504
Total Interruptible Service	302.20	4.634%	315.48	7.593%	4.278%	0.584%	4.862%	13,354,256	2,650,004	
VII. Lighting Service	7.99	0.122%	30.21	0.727%	0.112%	0.056%	0.168%	461,439	250,330	0.184
Total Retail	**6,521.73**	**100.000%**	**4,154.71**	**100.000%**	**92.307%**	**7.693%**	**100.000%**	**274,665,906**	**34,498,784**	**0.79478**

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS JANUARY THROUGH DECEMBER 2000

SCHEDULES E1 THROUGH E10 AND H1

Schedule	Description	Page
E1	Calculation of Basic Factor	1
E1-A	Calculation of Total True-Up (Projected Period)	2
E1-B, Sheet 1	Calculation of Estimated True-Up	3
E1-B, Sheet 2	Estimated/Actual vs. Original Projected Costs	4
E1-C	*Calcuation of Generating Performance Factor*	5
E1-D	Calcuation of Levelized Fuel Cost Factors	6
E1-E	Calcuation of Final Fuel Cost Factors	7
E1-F	Development of Jurisdictional and Retail Delivery Loss Multipliers	8
E2	Calculation of Basic Factor - Monthly	9
E3	Generating System Cost by Fuel Type	10-11
E4	System Net Generation and Fuel Cost	12-24
E5	Inventory Analysis	25-26
E6	Power Sold	27-28
E7	Purchased Power (Exclusive of Economy and Cogen Purchases)	29-30
E8	Energy Payment to Qualifying Facilities	31
E9	Economy Energy Purchases	32-33
E10	Residential Bill Comparison	34
H1	Generating System Comparative Data by Fuel Type	35

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

			DOLLARS	MWH		CENTS/KWH
1.	Fuel Cost of System Net Generation		600,315,215	31,551,516		1.90265
2.	Spent Nuclear Fuel Disposal Cost		5,935,404	6,348,026	*	0.09350
3.	Coal Car Investment		0	0		0.00000
4.	Adjustment to Fuel Cost		5,052,000	0		0.00000
5.	TOTAL COST OF GENERATED POWER		611,302,619	31,551,516		1.93747
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		36,511,925	2,504,288		1.45798
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0		0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		21,860,475	490,000		4.46132
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0		0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0	*	0.00000
11.	Payments to Qualifying Facilities (E8)		127,535,771	6,707,728		1.90133
12.	TOTAL COST OF PURCHASED POWER		185,908,171	9,702,016		1.91618
13.	TOTAL AVAILABLE KWH			41,253,532		
14.	Fuel Cost of Economy Sales	(E6)	0	0		0.00000
14a.	Gain on Economy Sales - 80%	(E6)	0	0	*	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(33,347,440)	(1,445,001)		2.30778
15a.	Gain on Other Power Sales	(E6)	0	(1,445,001)	*	0.00000
16.	Fuel Cost of Unit Power Sales	(E6)	0	0		0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0		0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(45,957,687)	(1,928,059)		2.38362
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(79,305,127)	(3,373,060)		2.35113
19.	Net Inadvertent Interchange			0		
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		717,905,663	37,880,472		1.89519
21.	Net Unbilled		1,403,973	(74,081)		0.00390
22.	Company Use		3,411,336	(180,000)		0.00960
23.	T & D Losses		39,099,748	(2,063,108)		0.10994
24.	Adjusted System KWH Sales		717,905,663	35,563,283		2.01863
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(20,193,502)	(1,004,677)		2.00995
26.	Jurisdictional KWH Sales		697,712,162	34,558,606		2.01892
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0026	699,526,213	34,558,606		2.02417
28.	Prior Period True-Up (E1-B, Sheet 1)**		7,346,176	34,558,606		0.02126
29.	Total Jurisdictional Fuel Cost		706,872,389	34,558,606		2.04543
30.	Revenue Tax Factor					1.00072
31.	Fuel Cost Adjusted for Taxes		707,381,337	34,558,606		2.04690
32.	GPIF **		1,047,140	34,558,606		0.00303
33.	Fuel Factor Adjusted for taxes including GPIF		708,428,477	34,558,606		2.04993
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)					2.050

* For Informational Purposes Only

** Based on Jurisdictional Sales

FLORIDA POWER CORPORATION
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

1.	ACTUAL OVER/(UNDER) RECOVERY APRIL - DECEMBER 1998 (Schedule E1-B, Lines 18 & 20 - Dec '99)	$ 21,595,398	
2.	AMOUNT OF DECEMBER 1998 OVER RECOVERY REFUNDED THROUGH DECEMBER 1999 (Schedule E1-B, Lines 19 & 21 - Dec '99)	(6,491,590)	
3.	ESTIMATED OVER/(UNDER) RECOVERY JANUARY - DECEMBER 1999 (Schedule E1-B, Line 17, Dec '99)	(22,449,984)	
4.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 through 3)	$ (7,346,176)	
5.	JURISDICTIONAL MWH SALES (Projected Period)	34,558,606	Mwh
6.	TRUE-UP FACTOR (Line 4 / Line 5 / 10)	0.02126	Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF ESTIMATED TRUE-UP
REPROJECTED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 1999

DESCRIPTION	ACTUALS Jan - Jul 99	ACTUALS Aug-99	ESTIMATED Sep-99	ESTIMATED Oct-99	ESTIMATED Nov-99	ESTIMATED Dec-99	TOTAL PERIOD
REVENUE							
1 Jurisdictional KWH Sales	18,493,440	3,877,765	3,323,285	3,011,759	2,582,902	2,593,532	33,882,683
2 Jurisdictional Fuel Factor (Pre-Tax)	1.862	1.753	1.891	1.891	1.891	1.891	
3 Total Jurisdictional Fuel Revenue	344,362,640	67,974,207	62,857,875	56,965,554	48,853,990	49,055,050	630,069,316
4 Less: True-Up Provision	8,655,430	1,236,490	1,236,490	1,236,490	1,236,490	1,236,490	14,837,880
5 Less: GPIF Provision	254,707	36,387	36,387	36,387	36,387	36,387	436,642
6 Less: Recovery of Replacement Costs	(8,346,290)	0	0	0	0	0	(8,346,290)
7 Net Fuel Revenue	344,926,487	69,247,084	64,130,752	58,238,431	50,126,867	50,327,927	636,997,548
FUEL EXPENSE							
8 Total Cost of Generated Power	302,255,834	72,279,918	57,651,238	50,109,139	40,253,349	43,160,020	565,709,498
9 Total Cost of Purchased Power	102,006,360	20,957,130	15,262,598	24,250,566	15,259,861	14,011,270	191,747,785
10 Total Cost of Power Sales	(40,968,714)	(10,878,039)	(8,292,065)	(7,583,579)	(3,801,147)	(5,340,502)	(76,864,046)
11 Total Fuel and Net Power	363,293,480	82,359,009	64,621,771	66,776,126	51,712,063	51,830,788	680,593,237
12 Jurisdictional Percentage	97.11%	96.32%	96.81%	96.79%	96.51%	96.99%	96.90%
13 Jurisdictional Loss Multiplier	1.0011	1.0011	1.0011	1.0011	1.0011	1.0011	1.0011
14 Jurisdictional Fuel Cost	353,209,849	79,415,458	62,629,153	64,703,708	49,962,210	50,325,979	660,246,358
COST RECOVERY							
15 Net Fuel Revenue Less Expense	(8,283,362)	(10,168,374)	1,501,599	(6,465,277)	164,657	1,948	
16 Interest Provision (1)	810,373	35,120	11,154	(4,898)	(23,914)	(29,011)	
17 Current Cycle Balance	(7,472,989)	(17,606,243)	(16,093,490)	(22,563,664)	(22,422,921)	(22,449,984)	
18 Plus: Replacement Cost Balance	(8,346,290)	(8,346,290)	(8,346,290)	(8,346,290)	(8,346,290)	(8,346,290)	
19 Plus: Cumulative Replmnt Cost Provision	8,346,290	8,346,290	8,346,290	8,346,290	8,346,290	8,346,290	
20 Plus: Prior Period True-Up Balance	29,941,688	29,941,688	29,941,688	29,941,688	29,941,688	29,941,688	
21 Plus: Cumulative True-Up Provision	(8,655,430)	(9,891,920)	(11,128,410)	(12,364,900)	(13,601,390)	(14,837,880)	
22 Total Retail Balance	13,813,269	2,443,525	2,719,788	(4,986,876)	(6,082,623)	(7,346,176)	

(1) Interest for the September through December 1999 period calculated at the August 1999 monthly rate of .433%.

FLORIDA POWER CORPORATION
COMPARISON OF ACTUAL/REVISED ESTIMATE VS. ORIGINAL ESTIMATE
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 1999

	DOLLARS				MWH				CENTS/KWH			
	Actual / Rev Estimate	Original Estimate	------Difference------ Amount	%	Actual / Rev Estimate	Original Estimate	Difference Amount	%	Actual / Rev Estimate	Original Estimate	----Difference---- Amount	%
1. Fuel Cost of System Net Generation	575,276,182	474,154,715	101,121,467	21.3	31,396,596	28,784,781	2,611,815	9.1	1.8323	1.6472	0.1850	11.2
2. Spent Nuclear Fuel Disposal Cost	5,388,779	5,094,565	294,214	5.8	5,474,537 *	5,448,733 *	25,804	0.5	0.0984	0.0935	0.0049	5.3
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4. Adjustment to Fuel Cost	(14,955,463)	4,896,000	(19,851,463)	(405.5)	(655,246)	0	(655,246)	0.0	2.2824	0.0000	2.2824	0.0
5. TOTAL COST OF GENERATED POWER	565,709,498	484,145,280	81,564,218	16.8	30,741,350	28,784,781	1,956,569	6.8	1.8402	1.6819	0.1583	9.4
6. Energy Cost of P. P. (Excl. Econ & Cogens)	38,088,224	42,715,660	(4,627,436)	(10.8)	2,282,490	2,239,993	42,497	1.9	1.6687	1.9070	(0.2382)	(12.5)
7. Energy Cost Econ Purch (Broker)	1,727,410	24,214,110	(22,486,700)	(92.9)	42,815	740,000	(697,185)	(94.2)	4.0346	3.2722	0.7624	23.3
8. Energy Cost of Econ Purch (Non-Broker)	23,695,743	1,418,360	22,277,383	--	610,445	41,580	568,865	--	3.8817	3.4112	0.4706	13.8
9. Energy Cost of Schedule E Economy Purch	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10. Capacity Cost of Economy Purchases	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
11. Payments to Qualifying Facilities	128,236,408	162,173,748	(33,937,340)	(20.9)	6,534,487	7,526,711	(992,224)	(13.2)	1.9625	2.1546	(0.1922)	(8.9)
12. TOTAL COST OF PURCHASED POWER	191,747,785	230,521,878	(38,774,093)	(16.8)	9,470,237	10,548,284	(1,078,047)	(10.2)	2.0247	2.1854	(0.1607)	(7.4)
13. TOTAL AVAILABLE KWH					40,211,587	39,333,065	878,522	2.2	--	--	--	--
14. Fuel Cost of Economy Sales	(155,467)	(17,487,400)	17,331,933	(99.1)	(10,210)	(1,060,000)	1,049,790	(99.0)	1.5227	1.6498	(0.1271)	(7.7)
14a. Gain on Economy Sales - 80%	(47,806)	(2,270,960)	2,223,154	(97.9)	(10,210) *	(1,060,000) *	1,049,790	(99.0)	0.4682	0.2142	0.2540	118.6
15. Fuel Cost of Other Power Sales	(31,805,435)	(6,978,560)	(24,826,875)	355.8	(1,417,750)	(282,875)	(1,134,875)	401.2	2.2434	2.4670	(0.2236)	(9.1)
15a. Gain on Other Power Sales	0	(4,050,000)	4,050,000	(100.0)	(1,417,750) *	(282,875) *	(1,134,875)	401.2	0.0000	1.4317	(1.4317)	(100.0)
16. Fuel Cost of Unit Power Sales	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16a. Gain on Unit Power Sales	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
17. Fuel Cost of Stratified Sales	(44,855,338)	(33,227,981)	(11,627,357)	35.0	(1,781,080)	(1,549,090)	(231,990)	15.0	2.5184	2.1450	0.3734	17.4
18. TOTAL FUEL COST & GAINS ON POWER SALES	(76,864,046)	(64,014,901)	(12,849,145)	20.1	(3,209,040)	(2,891,965)	(317,075)	11.0	2.3952	2.2135	0.1817	8.2
19. Net Inadvertent Interchange					16,387	0	16,387	0.0	--	--	--	--
20. TOTAL FUEL & NET POWER TRANSACTIONS	680,593,237	650,652,257	29,940,980	4.6	37,018,934	36,441,100	577,834	1.6	1.8385	1.7855	0.0530	3.0
21. Net Unbilled	4,483,735 *	2,577,694 *	1,906,041	73.9	(243,880)	(144,369)	(99,511)	68.9	0.0128	0.0076	0.0053	69.4
22. Company Use	2,610,818 *	3,246,021 *	(635,203)	(19.6)	(142,008)	(181,800)	39,792	(21.9)	0.0075	0.0095	(0.0021)	(21.7)
23. T & D Losses	30,666,572 *	36,943,541 *	(6,276,969)	(17.0)	(1,668,021)	(2,069,098)	401,077	(19.4)	0.0877	0.1085	(0.0208)	(19.2)
24. Adjusted System KWH Sales	680,593,237	650,652,257	29,940,980	4.6	34,965,025	34,045,833	919,192	2.7	1.9465	1.9111	0.0354	1.9
25. Wholesale KWH Sales (Excl Suppl. Sales)	(21,078,551)	(19,631,822)	(1,446,729)	7.4	(1,082,342)	(1,027,430)	(54,912)	5.3	1.9475	1.9108	0.0367	1.9
26. Jurisdictional KWH Sales	659,514,686	631,020,435	28,494,251	4.5	33,882,683	33,018,403	864,280	2.6	1.9465	1.9111	0.0353	1.8
27. Jurisd KWH Sales Adj for Line Losses	660,246,358	631,714,558	28,531,800	4.5	33,882,683	33,018,403	864,280	2.6	1.9486	1.9132	0.0354	1.9
28. Prior Period True-Up **	(14,837,877)	(14,837,877)	0	0.0	33,882,683	33,018,403	864,280	2.6	(0.0438)	(0.0449)	0.0011	(2.6)
28a. Market Price True-Up **	0	(263,847)	263,847	(100.0)	33,882,683	33,018,403	864,280	2.6	0.0000	(0.0008)	0.0008	(100.0)
29. Total Jurisdictional Fuel Cost	645,408,481	616,612,834	28,795,647	4.7	33,882,683	33,018,403	864,280	2.6	1.9048	1.8675	0.0374	2.0
30. Revenue Tax Factor									1.00072	1.00072	0.0000	0.0
31. Fuel Cost Adjusted for Taxes									1.9062	1.8688	0.0374	2.0
32. GPIF **	(436,639)	(436,639)	0	0.0	33,882,683	33,018,403	864,280	2.6	(0.0013)	(0.0013)	0.0000	(2.6)
33. Nuclear Replacement Cost	8,346,290	8,346,290	0	0.0	33,882,683	33,018,403	864,280	2.6	0.0246	0.0253	(0.0006)	(2.6)
34. Total Fuel Cost Factor									1.930	1.893	0.037	1.9

FLORIDA POWER CORPORATION
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	1,047,140
	B. True-Up (Over) / Under Recovery	$	7,346,176
2.	JURISDICTIONAL MWH SALES		34,558,606 Mwh
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.00303 Cents/kwh
	B. True-Up Factor		0.02126 Cents/kwh

FLORIDA POWER CORPORATION
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$ 699,526,213	
2.	Prior Period True-Up (E1, line 28)	7,346,176	
3.	Market Price True-Up (E1, line 28a)	0	
4.	Regulatory Assessment Fee (E1, line 30)	508,948	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	1,047,140	
6.	Total Jurisdictional Fuel Cost	$ 708,428,477	
7.	Jurisdictional Sales	34,558,606	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 7 / Line 8 / 10)	2.050	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	34,498,784	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**2.053**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**2.032**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**2.012**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	29,146,720	29,146,720
Distribution Primary	4,841,447	4,793,034
Transmission	570,439	559,030
Total	34,558,606	34,498,784

FLORIDA POWER CORPORATION
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

Line:	Metering Voltage	(1) Levelized Factors Cents/Kwh	(2) Time of Use On-Peak Multiplier 1.262	(3) Time of Use Off-Peak Multiplier 0.885
1.	Distribution Secondary	2.053	2.591	1.817
2.	Distribution Primary	2.032	2.564	1.798
3.	Transmission	2.012	2.539	1.781
4.	Lighting Service	1.962	--	--

Line 4 Calculated as secondary rate 2.053 * (18.7% * On-Peak Multiplier 1.262 + 81.3% * Off-Peak Multiplier 0.885).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
1/00	757,258	16,720,257	2.208	2,260,248	42,560,472	1.883	3,017,506	59,280,729	1.965
2/00	758,497	17,430,261	2.298	2,057,043	38,363,852	1.865	2,815,540	55,794,113	1.982
3/00	753,663	19,678,141	2.611	2,163,421	55,859,535	2.582	2,917,084	75,537,676	2.589
4/00	866,242	24,436,687	2.821	1,983,201	40,873,773	2.061	2,849,443	65,310,460	2.292
5/00	1,247,992	38,849,994	3.113	2,295,496	44,486,714	1.938	3,543,488	83,336,708	2.352
6/00	1,293,446	43,265,772	3.345	2,508,237	55,381,877	2.208	3,801,683	98,647,649	2.595
7/00	1,293,660	48,770,986	3.770	2,723,207	60,564,126	2.224	4,016,867	109,335,112	2.722
8/00	1,432,352	55,632,556	3.884	2,690,889	61,782,814	2.296	4,123,241	117,415,370	2.848
9/00	1,182,959	36,423,311	3.079	2,492,730	52,571,678	2.109	3,675,689	88,994,989	2.421
10/00	1,027,703	26,247,535	2.554	2,142,946	39,537,354	1.845	3,170,649	65,784,889	2.075
11/00	720,172	16,203,870	2.250	2,052,157	44,490,766	2.168	2,772,329	60,694,636	2.189
12/00	802,737	19,129,223	2.383	2,299,459	43,850,685	1.907	3,102,196	62,979,908	2.030
TOTAL	12,136,682	362,788,593	2.989	27,669,035	580,323,646	2.097	39,805,717	943,112,239	2.369
MARGINAL FUEL COST			ON-PEAK			OFF-PEAK			AVERAGE
WEIGHTING MULTIPLIER			1.262			0.885			1.000

FLORIDA POWER CORPORATION
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 1998 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	591,561	1,139	592,700		0.9790000	605,414		
2. Distribution Primary	4,815,638	9,270	4,824,908		0.9690000	4,979,265		
3. Distribution Secondary	27,979,413	53,863	28,033,276		0.9458216	29,639,074		
Total Retail	33,386,612	64,272	33,450,884	93.68%	0.9496684	35,223,753	93.92%	1.0026
B. WHOLESALE								
1. Source Level	1,395,119	(39,920)	1,355,199		1.0000000	1,355,199		
2. Transmission	798,682	(1,391)	797,291		0.9790000	814,393		
3. Distribution Primary	106,040	8	106,048		0.9690000	109,441		
4. Distribution Secondary	0	0	0		0.9458216	0		
Total Wholesale	2,299,841	(41,303)	2,258,538	6.32%	0.9910070	2,279,033	6.08%	0.9608
Total Class Loads	35,686,453	22,969	35,709,422	100.00%	0.9521805	37,502,786	100.00%	1.0000
II. NON-CLASS LOADS								
1. Company Use	176,491	0	176,491		0.9458216	186,601		
2. Seminole Electric	0	0	0		1.0000000	0		
3. Kissimmee	0	0	0		0.9790000	0		
4. St. Cloud	0	0	0		0.9790000	0		
5. Interchange	1,524,750	0	1,524,750		0.9790000	1,557,457		
6. SEPA	39,874	0	39,874		0.9790000	40,729		
Total Non-Class Loads	1,741,115	0	1,741,115		0.9755310	1,784,787		
Total System	37,427,568	22,969	37,450,537		0.9532413	39,287,573		

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

	DESCRIPTION		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	TOTAL
1	Fuel Cost of System Net Generation		$42,021,664	$40,350,526	$46,072,150	$39,527,931	$51,619,829	$61,776,329	$68,592,818	$71,418,355	$57,945,639	$42,550,595	$36,784,402	$41,654,977	$600,315,215
1a	Nuclear Fuel Disposal Cost		508,718	470,877	515,270	486,434	501,186	482,589	494,872	493,442	483,911	498,449	491,497	508,160	5,935,404
1b	Adjustments to Fuel Cost		314,000	311,000	309,000	307,000	304,000	302,000	299,000	297,000	295,000	1,808,000	257,000	249,000	5,052,000
2	Fuel Cost of Power Sold		(1,633,821)	(2,823,616)	(3,197,872)	(1,642,243)	(1,222,102)	(3,054,998)	(5,105,994)	(4,725,020)	(3,525,068)	(2,256,789)	(2,147,657)	(2,012,260)	(33,347,440)
2a	Fuel Cost of Stratified Sales		(2,061,439)	(4,078,045)	(4,152,431)	(2,798,330)	(3,186,959)	(1,972,175)	(4,015,284)	(5,491,501)	(6,678,754)	(5,953,887)	(2,588,346)	(2,980,536)	(45,957,687)
2b	Gains on Power Sales		-	-	-	-	-	-	-	-	-	-	-	-	-
3	Energy Cost of Purchased Power		2,941,815	2,766,481	3,199,905	2,959,542	3,121,490	3,092,809	3,228,713	3,274,805	3,015,375	3,005,522	2,932,081	2,973,387	36,511,925
3a	Capacity Cost of Economy Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-
3b	Payments to Qualifying Facilities		10,187,502	9,774,500	9,660,564	9,500,330	11,107,002	11,617,467	12,013,551	12,250,854	11,528,325	9,992,217	9,390,306	10,513,153	127,535,771
4	Energy Cost of Economy Purchases		354,514	348,221	564,094	2,580,861	2,804,999	2,499,962	2,529,769	3,503,176	2,255,591	2,481,654	1,375,164	562,470	21,860,475
5	Total Fuel & Net Power Transactions		$52,632,953	$47,119,944	$52,970,680	$50,921,525	$65,049,445	$74,743,983	$78,037,445	$81,021,111	$65,320,019	$52,125,761	$46,494,447	$51,468,351	$717,905,663
6	Adjusted System Sales	MWH	2,700,153	2,684,863	2,555,889	2,625,448	2,739,610	3,183,900	3,503,095	3,461,321	3,576,666	3,163,599	2,716,321	2,652,418	35,563,283
7	System Cost per KWH Sold	c/kwh	1.9493	1.7551	2.0725	1.9394	2.3744	2.3475	2.2276	2.3407	1.8264	1.6477	1.7117	1.9404	2.0188
7a	Jurisdictional Loss Multiplier	x	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
7b	Jurisdictional Cost per KWH Sold	c/kwh	1.9543	1.7596	2.0779	1.9446	2.3806	2.3537	2.2335	2.3468	1.8310	1.6520	1.7161	1.9455	2.0242
8	Prior Period True-Up *	c/kwh	0.0234	0.0235	0.0246	0.0240	0.0230	0.0198	0.0180	0.0182	0.0176	0.0199	0.0232	0.0237	0.0213
9	Total Jurisdictional Fuel Expense	c/kwh	1.9777	1.7831	2.1025	1.9685	2.4035	2.3734	2.2514	2.3651	1.8487	1.6719	1.7394	1.9692	2.0454
10	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	1.9791	1.7844	2.1040	1.9699	2.4053	2.3751	2.2530	2.3668	1.8500	1.6731	1.7406	1.9706	2.0469
12	GPIF	c/kwh	0.0033	0.0034	0.0035	0.0034	0.0033	0.0028	0.0026	0.0026	0.0025	0.0028	0.0033	0.0034	0.0033
13	Total Fuel Cost Factor (rounded .001)	c/kwh	1.982	1.788	2.108	1.973	2.409	2.378	2.256	2.369	1.852	1.676	1.744	1.974	2.056

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

			Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		5,595,424	4,766,563	14,109,909	13,582,094	14,141,219	15,133,468	67,328,677
2	LIGHT OIL		2,570,259	2,523,166	3,730,886	1,141,623	2,116,164	5,749,182	17,831,282
3	COAL		21,126,671	20,844,585	15,552,316	11,552,176	20,149,625	23,220,102	112,445,475
4	GAS		10,885,000	10,509,089	10,810,971	11,479,072	13,390,508	15,892,483	72,967,122
5	NUCLEAR		1,844,311	1,707,124	1,868,066	1,772,965	1,822,313	1,781,094	10,795,873
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	42,021,665	40,350,526	46,072,150	39,527,931	51,619,829	61,776,329	281,368,429
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		200,039	167,936	520,072	516,535	550,194	594,562	2,549,338
9	LIGHT OIL		41,827	40,030	60,084	20,055	36,650	91,172	289,818
10	COAL		1,178,348	1,171,753	897,885	653,586	1,138,792	1,319,118	6,359,482
11	GAS		385,863	374,846	335,322	438,157	477,602	520,668	2,532,458
12	NUCLEAR		544,083	503,612	551,091	520,250	536,028	516,138	3,171,202
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,350,160	2,258,177	2,364,454	2,148,583	2,739,266	3,041,658	14,902,298
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	321,903	272,329	802,797	812,861	870,586	940,794	4,021,289
16	LIGHT OIL	BBL	96,803	93,532	137,084	42,389	78,955	213,913	662,678
17	COAL	TON	450,688	446,304	340,576	248,746	434,655	503,596	2,424,567
18	GAS	MCF	3,049,891	3,023,432	3,195,939	3,641,497	4,276,264	5,047,973	22,234,997
19	NUCLEAR	MMBTU	5,588,821	5,173,102	5,660,807	5,372,622	5,522,160	5,397,255	32,714,767
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		2,060,178	1,742,904	5,137,903	5,202,441	5,571,741	6,021,084	25,736,250
22	LIGHT OIL		561,458	542,488	795,090	245,856	457,941	1,240,698	3,843,531
23	COAL		11,324,925	11,215,079	8,562,600	6,251,268	10,923,584	12,657,693	60,935,147
24	GAS		3,049,891	3,023,432	3,195,939	3,641,497	4,276,264	5,047,973	22,234,997
25	NUCLEAR		5,588,821	5,173,102	5,660,807	5,372,622	5,522,160	5,397,255	32,714,767
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	22,585,272	21,697,005	23,352,339	20,713,682	26,751,691	30,364,703	145,464,692
	GENERATION MIX (% MWH)								
28	HEAVY OIL		8.51%	7.44%	22.00%	24.04%	20.09%	19.55%	17.11%
29	LIGHT OIL		1.78%	1.77%	2.54%	0.93%	1.34%	3.00%	1.95%
30	COAL		50.14%	51.89%	37.97%	30.42%	41.57%	43.37%	42.68%
31	GAS		16.42%	16.60%	14.18%	20.39%	17.44%	17.12%	16.99%
32	NUCLEAR		23.15%	22.30%	23.31%	24.21%	19.57%	16.97%	21.28%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	17.38	17.50	17.58	16.71	16.24	16.09	16.74
36	LIGHT OIL	$/BBL	26.55	26.98	27.22	26.93	26.80	26.88	26.91
37	COAL	$/TON	46.88	46.70	45.66	46.44	46.36	46.11	46.38
38	GAS	$/MCF	3.57	3.48	3.38	3.15	3.13	3.15	3.28
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.72	2.74	2.75	2.61	2.54	2.51	2.62
42	LIGHT OIL		4.58	4.65	4.69	4.64	4.62	4.63	4.64
43	COAL		1.87	1.86	1.82	1.85	1.85	1.83	1.85
44	GAS		3.57	3.48	3.38	3.15	3.13	3.15	3.28
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	1.86	1.86	1.97	1.91	1.93	2.03	1.93
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,299	10,378	9,879	10,072	10,127	10,127	10,095
49	LIGHT OIL		13,423	13,552	13,233	12,259	12,495	13,608	13,262
50	COAL		9,611	9,571	9,536	9,565	9,592	9,596	9,562
51	GAS		7,904	8,066	9,531	8,311	8,954	9,695	8,780
52	NUCLEAR		10,272	10,272	10,272	10,327	10,302	10,457	10,316
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,610	9,608	9,876	9,641	9,766	9,983	9,761
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.80	2.84	2.71	2.63	2.57	2.55	2.64
56	LIGHT OIL		6.14	6.30	6.21	5.69	5.77	6.31	6.15
57	COAL		1.79	1.78	1.73	1.77	1.77	1.76	1.77
58	GAS		2.82	2.80	3.22	2.62	2.80	3.05	2.88
59	NUCLEAR		0.34	0.34	0.34	0.34	0.34	0.35	0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	1.79	1.79	1.95	1.84	1.88	2.03	1.89

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

			Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		16,755,626	17,274,073	13,648,513	7,502,270	5,423,641	5,997,677	133,930,478
2	LIGHT OIL		7,839,066	9,562,942	4,391,028	1,041,579	1,726,583	1,335,679	43,728,159
3	COAL		25,088,823	25,366,779	23,937,998	23,139,429	20,632,670	22,868,575	253,479,749
4	GAS		17,079,731	17,390,278	14,178,369	9,054,430	7,208,180	9,610,218	147,488,328
5	NUCLEAR		1,829,571	1,824,283	1,789,731	1,812,887	1,793,327	1,842,829	21,688,500
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	68,592,818	71,418,355	57,945,639	42,550,595	36,784,402	41,654,977	600,315,215
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		660,548	684,638	540,893	283,791	204,253	220,905	5,144,366
9	LIGHT OIL		123,579	147,907	69,402	17,764	29,194	21,991	699,655
10	COAL		1,428,677	1,447,166	1,361,264	1,314,965	1,176,585	1,303,391	14,391,530
11	GAS		535,673	548,008	457,875	333,454	223,780	336,691	4,967,939
12	NUCLEAR		529,275	527,745	517,552	533,100	525,665	543,487	6,348,026
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,277,752	3,355,464	2,946,986	2,483,074	2,159,477	2,426,465	31,551,516
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,044,057	1,078,817	861,628	458,873	326,328	351,918	8,142,910
16	LIGHT OIL	BBL	291,453	355,675	163,082	38,353	63,461	48,567	1,623,269
17	COAL	TON	544,020	550,284	518,521	500,187	448,378	493,496	5,479,453
18	GAS	MCF	5,427,305	5,465,328	4,523,241	2,774,825	2,017,237	2,788,964	45,231,896
19	NUCLEAR	MMBTU	5,544,156	5,528,129	5,423,427	5,493,596	5,434,325	5,584,329	65,722,728
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		6,681,966	6,904,429	5,514,418	2,936,790	2,088,496	2,252,273	52,114,622
22	LIGHT OIL		1,690,428	2,062,913	945,874	222,449	368,076	281,688	9,414,959
23	COAL		13,673,550	13,831,102	13,032,307	12,570,841	11,270,130	12,402,194	137,715,270
24	GAS		5,427,305	5,465,328	4,523,241	2,774,825	2,017,237	2,788,964	45,231,896
25	NUCLEAR		5,544,156	5,528,129	5,423,427	5,493,596	5,434,325	5,584,329	65,722,728
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	33,017,405	33,791,901	29,439,267	23,998,500	21,178,264	23,309,447	310,199,475
	GENERATION MIX (% MWH)								
28	HEAVY OIL		20.15%	20.40%	18.35%	11.43%	9.46%	9.10%	16.31%
29	LIGHT OIL		3.77%	4.41%	2.36%	0.72%	1.35%	0.91%	2.22%
30	COAL		43.59%	43.13%	46.19%	52.96%	54.49%	53.72%	45.61%
31	GAS		16.34%	16.33%	15.54%	13.43%	10.36%	13.88%	15.75%
32	NUCLEAR		16.15%	15.73%	17.56%	21.47%	24.34%	22.40%	20.12%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	16.05	16.01	15.84	16.35	16.62	17.04	16.45
36	LIGHT OIL	$/BBL	26.90	26.89	26.93	27.16	27.21	27.50	26.94
37	COAL	$/TON	46.12	46.10	46.17	46.26	46.02	46.34	46.26
38	GAS	$/MCF	3.15	3.18	3.13	3.26	3.57	3.45	3.26
39	NUCLEAR	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		2.51	2.50	2.48	2.56	2.60	2.66	2.57
42	LIGHT OIL		4.64	4.64	4.64	4.68	4.69	4.74	4.65
43	COAL		1.84	1.83	1.84	1.84	1.83	1.84	1.84
44	GAS		3.15	3.18	3.14	3.26	3.57	3.45	3.26
45	NUCLEAR		0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	2.08	2.11	1.97	1.77	1.74	1.79	1.94
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,116	10,085	10,195	10,348	10,225	10,196	10,130
49	LIGHT OIL		13,679	13,947	13,629	12,522	12,608	12,809	13,457
50	COAL		9,571	9,557	9,574	9,560	9,579	9,515	9,569
51	GAS		10,132	9,973	9,879	8,321	9,014	8,283	9,105
52	NUCLEAR		10,475	10,475	10,479	10,305	10,338	10,275	10,353
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	10,073	10,071	9,990	9,665	9,807	9,606	9,832
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		2.54	2.52	2.52	2.64	2.66	2.72	2.60
56	LIGHT OIL		6.34	6.47	6.33	5.86	5.91	6.07	6.25
57	COAL		1.76	1.75	1.76	1.76	1.75	1.75	1.76
58	GAS		3.19	3.17	3.10	2.72	3.22	2.85	2.97
59	NUCLEAR		0.35	0.35	0.35	0.34	0.34	0.34	0.34
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	2.09	2.13	1.97	1.71	1.70	1.72	1.90

SCHEDULE E4

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jan-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	544,083	93.5	93.5	97.4	10,272	NUCLEAR	5,588,821 MMBTU	1.00	5,588,821	1,844,311	0.34
2 ANCLOTE	1	517	65,713	17.1	98.2	40.1	10,220	HEAVY OIL	104,935 BBLS	6.40	671,587	1,810,136	2.75
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	517	61,755	16.1	97.3	44.7	10,149	HEAVY OIL	97,930 BBLS	6.40	626,751	1,689,291	2.74
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	117	17,878	20.5	99.1	59.7	10,389	HEAVY OIL	29,021 BBLS	6.40	185,735	500,613	2.80
7 BARTOW	2	119	11,493	13.0	99.3	60.4	10,521	HEAVY OIL	18,893 BBLS	6.40	120,918	325,911	2.84
8 BARTOW	3	213	35,698	22.5	96.2	54.8	10,401	HEAVY OIL	58,015 BBLS	6.40	371,295	1,000,756	2.80
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	165,604	59.7	89.8	69.6	10,036	COAL	65,952 TONS	25.20	1,662,002	2,731,091	1.65
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	469	148,359	42.5	90.0	54.3	10,288	COAL	60,568 TONS	25.20	1,526,317	2,508,127	1.69
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	717	367,262	68.8	93.0	73.1	9,542	COAL	139,618 TONS	25.10	3,504,414	6,842,682	1.86
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	734	497,123	91.0	97.2	92.5	9,318	COAL	184,549 TONS	25.10	4,632,192	9,044,770	1.82
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	34	1,444	5.7	99.5	63.4	11,857	HEAVY OIL	2,675 BBLS	6.40	17,122	54,842	3.80
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	33	1,292	5.3	99.6	68.7	12,722	HEAVY OIL	2,568 BBLS	6.40	16,437	52,649	4.08
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	4,766	8.0	99.4	65.5	10,561	HEAVY OIL	7,865 BBLS	6.40	50,334	161,225	3.38
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	64	764	1.6	100.0	68.2	18,230	LIGHT OIL	2,401 BBLS	5.80	13,928	63,923	8.37
25 BARTOW	1-4	217	1,027	2.8	100.0	62.7	14,899	LIGHT OIL	2,638 BBLS	5.80	15,301	70,069	6.82
26 BARTOW	1-4		3,529				15,220	GAS	53,711 MCF	1.00	53,711	160,597	4.55
27 BAYBORO	1-4	232	4,883	2.8	100.0	63.3	15,899	LIGHT OIL	13,385 BBLS	5.80	77,635	355,514	7.28
28 DEBARY	1-10	786	10,433	4.4	100.0	58.8	13,344	LIGHT OIL	24,003 BBLS	5.80	139,218	651,444	6.24
29 DEBARY	1-10		15,013				13,526	GAS	203,066 MCF	1.00	203,066	607,167	4.04
30 HIGGINS	1-4	148	0	0.0	100.0	30.1	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		1,913				17,142	GAS	32,793 MCF	1.00	32,793	98,050	5.13
32 HINES	1	505	309,752	82.4	96.5	84.8	6,875	GAS	2,129,545 MCF	1.00	2,129,545	6,367,340	2.06
33 INT CITY	1-10	757	8,525	5.3	100.0	59.6	15,332	LIGHT OIL	22,535 BBLS	5.80	130,705	586,822	6.88
34 INT CITY	1-10		21,147				13,723	GAS	290,200 MCF	1.00	290,200	867,699	4.10
35 INT CITY	11	168	6,381	5.1	100.0	77.5	11,162	LIGHT OIL	12,280 BBLS	5.80	71,225	319,774	5.01
36 RIO PINAR	1	18	86	0.6	100.0	39.8	16,160	LIGHT OIL	240 BBLS	5.80	1,390	6,405	7.45
37 SUWANNEE	1-3	201	1,249	3.5	100.0	65.0	14,554	LIGHT OIL	3,134 BBLS	5.80	18,178	83,963	6.72
38 SUWANNEE	1-3		3,975				13,842	GAS	55,022 MCF	1.00	55,022	164,516	4.14
39 TURNER	1-4	200	1,429	1.0	100.0	40.4	17,100	LIGHT OIL	4,213 BBLS	5.80	24,436	113,627	7.95
40 UNIV OF FLA.	1	42	30,534	97.7	97.4	100.0	9,352	GAS	285,554 MCF	1.00	285,554	675,327	2.21
41 OTHER - START UP		-	7,050	-		-	9,850	LIGHT OIL	11,973 BBLS	5.80	69,443	318,717	4.52
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,944,305	-
43 TOTAL		8,043	2,350,160				9,610				22,585,272	42,021,665	1.79

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Feb-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	503,612	92.5	93.5	97.4	10,272 NUCLEAR	5,173,102 MMBTU	1.00	5,173,102	1,707,124	0.34
2	ANCLOTE	1	517	55,106	15.3	74.2	39.5	10,235 HEAVY OIL	88,127 BBLS	6.40	564,010	1,528,114	2.77
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	517	48,312	13.7	83.7	40.6	10,337 HEAVY OIL	79,647 BBLS	6.40	509,738	1,381,072	2.80
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	117	18,047	22.2	99.0	55.7	10,502 HEAVY OIL	29,614 BBLS	6.40	189,530	513,507	2.85
7	BARTOW	2	119	11,449	13.8	99.3	63.7	10,450 HEAVY OIL	18,694 BBLS	6.40	119,642	324,155	2.83
8	BARTOW	3	213	26,339	17.8	83.1	54.0	10,349 HEAVY OIL	42,591 BBLS	6.40	272,582	738,528	2.80
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	161,946	62.4	89.8	72.6	9,980 COAL	64,136 TONS	25.20	1,616,221	2,642,393	1.63
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	469	158,060	48.4	88.9	55.4	10,257 COAL	64,334 TONS	25.20	1,621,221	2,650,568	1.68
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	717	378,458	75.8	93.0	80.5	9,454 COAL	142,547 TONS	25.10	3,577,942	6,974,849	1.84
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	734	473,289	92.6	97.2	95.2	9,296 COAL	175,287 TONS	25.10	4,399,695	8,576,775	1.81
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	34	1,622	6.9	99.4	59.6	11,899 HEAVY OIL	3,016 BBLS	6.40	19,300	62,092	3.83
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	33	1,635	7.1	99.4	62.7	12,936 HEAVY OIL	3,305 BBLS	6.40	21,150	68,045	4.16
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	4,426	7.9	99.3	60.8	10,608 HEAVY OIL	7,336 BBLS	6.40	46,951	151,050	3.41
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	64	569	1.3	100.0	59.3	18,053 LIGHT OIL	1,771 BBLS	5.80	10,272	47,890	8.42
25	BARTOW	1-4	217	1,004	3.4	100.0	58.5	15,522 LIGHT OIL	2,687 BBLS	5.80	15,584	72,493	7.22
26	BARTOW	1-4		4,071				14,831 GAS	60,377 MCF	1.00	60,377	174,490	4.29
27	BAYBORO	1-4	232	4,036	2.5	100.0	62.1	16,125 LIGHT OIL	11,221 BBLS	5.80	65,081	302,737	7.50
28	DEBARY	1-10	786	9,850	5.3	100.0	53.8	14,331 LIGHT OIL	24,338 BBLS	5.80	141,160	670,755	6.81
29	DEBARY	1-10		19,110				13,283 GAS	253,838 MCF	1.00	253,838	733,592	3.84
30	HIGGINS	1-4	148	0	0.0	100.0	25.6	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		2,016				16,850 GAS	33,970 MCF	1.00	33,970	98,172	4.87
32	HINES	1	505	290,325	82.6	96.5	85.0	6,875 GAS	1,995,984 MCF	1.00	1,995,984	5,768,395	1.99
33	INT CITY	1-10	757	6,794	6.2	100.0	60.4	15,585 LIGHT OIL	18,256 BBLS	5.80	105,884	483,052	7.11
34	INT CITY	1-10		26,089				13,270 GAS	346,201 MCF	1.00	346,201	1,000,521	3.84
35	INT CITY	11	168	8,271	7.1	100.0	75.7	11,206 LIGHT OIL	15,980 BBLS	5.80	92,685	422,835	5.11
36	RIO PINAR	1	18	30	0.2	100.0	27.8	17,142 LIGHT OIL	89 BBLS	5.80	514	2,407	8.02
37	SUWANNEE	1-3	201	1,254	4.2	100.0	57.5	15,796 LIGHT OIL	3,415 BBLS	5.80	19,808	92,928	7.41
38	SUWANNEE	1-3		4,675				14,111 GAS	65,969 MCF	1.00	65,969	190,650	4.08
39	TURNER	1-4	200	1,447	1.0	100.0	46.2	17,115 LIGHT OIL	4,270 BBLS	5.80	24,765	116,952	8.08
40	UNIV OF FLA.	1	42	28,560	97.7	97.4	100.0	9,352 GAS	267,093 MCF	1.00	267,093	575,401	2.01
41	OTHER - START UP		-	6,775	-	-	-	9,850 LIGHT OIL	11,506 BBLS	5.80	66,734	311,117	4.59
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,967,868	-
43	TOTAL	8,043	2,258,177				9,608				21,697,005	40,350,526	1.79

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Mar-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	551,091	94.7	93.4	97.5	10,272 NUCLEAR	5,660,807 MMBTU	1.00	5,660,807	1,868,066	0.34
2	ANCLOTE	1	517	198,057	51.5	96.0	55.9	9,777 HEAVY OIL	302,563 BBLS	6.40	1,936,403	5,288,801	2.67
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	517	195,336	50.8	84.0	60.6	9,728 HEAVY OIL	296,911 BBLS	6.40	1,900,229	5,189,999	2.66
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	117	53,774	61.8	97.9	74.1	10,107 HEAVY OIL	84,921 BBLS	6.40	543,494	1,484,417	2.76
7	BARTOW	2	119	40,034	45.2	98.0	73.6	10,295 HEAVY OIL	64,398 BBLS	6.40	412,150	1,125,685	2.81
8	BARTOW	3	213	19,330	12.2	20.7	61.7	10,035 HEAVY OIL	30,309 BBLS	6.40	193,977	529,798	2.74
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	229,770	82.8	88.6	86.8	9,824 COAL	89,574 TONS	25.20	2,257,260	3,681,484	1.60
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	469	131,883	37.8	48.8	79.7	9,925 COAL	51,942 TONS	25.20	1,308,939	2,134,817	1.62
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	717	33,753	6.3	9.0	72.4	9,550 COAL	12,842 TONS	25.10	322,341	628,116	1.86
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	734	502,479	92.0	97.2	94.6	9,302 COAL	186,218 TONS	25.10	4,674,060	9,107,899	1.81
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	34	2,415	9.5	99.2	62.9	11,859 HEAVY OIL	4,475 BBLS	6.40	28,639	92,765	3.84
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	33	2,368	9.6	99.2	65.2	12,836 HEAVY OIL	4,749 BBLS	6.40	30,396	98,453	4.16
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	8,758	14.7	98.8	63.3	10,575 HEAVY OIL	14,471 BBLS	6.40	92,616	299,989	3.43
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	64	1,581	3.3	100.0	63.3	16,302 LIGHT OIL	4,444 BBLS	5.80	25,773	121,446	7.68
25	BARTOW	1-4	217	2,953	6.0	100.0	66.9	14,675 LIGHT OIL	7,472 BBLS	5.80	43,335	203,751	6.90
26	BARTOW	1-4		6,663				14,542 GAS	96,893 MCF	1.00	96,893	272,270	4.09
27	BAYBORO	1-4	232	5,997	3.5	100.0	60.5	14,329 LIGHT OIL	14,816 BBLS	5.80	85,931	404,024	6.74
28	DEBARY	1-10	786	13,194	9.7	100.0	66.4	13,580 LIGHT OIL	30,892 BBLS	5.80	179,175	860,347	6.52
29	DEBARY	1-10		43,778				13,318 GAS	583,035 MCF	1.00	583,035	1,638,329	3.74
30	HIGGINS	1-4	148	0	0.0	100.0	43.8	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		5,173				17,076 GAS	88,334 MCF	1.00	88,334	248,219	4.80
32	HINES	1	505	182,454	48.6	52.9	91.9	6,879 GAS	1,255,101 MCF	1.00	1,255,101	3,526,834	1.93
33	INT CITY	1-10	757	16,179	12.9	100.0	70.1	13,908 LIGHT OIL	38,796 BBLS	5.80	225,018	1,037,796	6.41
34	INT CITY	1-10		56,716				13,258 GAS	751,941 MCF	1.00	751,941	2,112,953	3.73
35	INT CITY	11	168	9,437	7.6	100.0	75.9	11,447 LIGHT OIL	18,625 BBLS	5.80	108,025	498,220	5.28
36	RIO PINAR	1	18	144	1.1	100.0	38.1	18,350 LIGHT OIL	456 BBLS	5.80	2,642	12,501	8.68
37	SUWANNEE	1-3	201	1,050	7.5	100.0	69.0	13,520 LIGHT OIL	2,448 BBLS	5.80	14,196	67,309	6.41
38	SUWANNEE	1-3		10,130				13,451 GAS	136,259 MCF	1.00	136,259	382,887	3.78
39	TURNER	1-4	200	2,456	1.7	100.0	40.9	16,748 LIGHT OIL	7,091 BBLS	5.80	41,128	196,281	7.99
40	UNIV OF FLA.	1	42	30,408	97.3	97.4	100.0	9,352 GAS	284,376 MCF	1.00	284,376	600,986	1.98
41	OTHER - START UP		-	7,093	-	-	-	9,850 LIGHT OIL	12,046 BBLS	5.80	69,866	329,214	4.64
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP	-	-	-	2,028,491	-
43	TOTAL	8,043	2,364,454				9,876				23,352,339	46,072,150	1.95

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Apr-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	520,250	92.4	93.5	97.1	10,327 NUCLEAR	5,372,622 MMBTU	1.00	5,372,622	1,772,965	0.34
2	ANCLOTE	1	517	178,621	48.0	95.8	49.9	9,929 HEAVY OIL	277,114 BBLS	6.40	1,773,528	4,602,859	2.58
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	517	172,456	46.3	93.3	52.5	9,988 HEAVY OIL	269,139 BBLS	6.40	1,722,491	4,470,401	2.59
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	117	38,190	45.3	74.9	64.6	10,323 HEAVY OIL	61,599 BBLS	6.40	394,235	1,023,164	2.68
7	BARTOW	2	119	34,074	39.8	98.0	65.4	10,476 HEAVY OIL	55,775 BBLS	6.40	356,959	926,421	2.72
8	BARTOW	3	213	79,259	51.7	91.9	59.4	10,061 HEAVY OIL	124,598 BBLS	6.40	797,425	2,069,567	2.61
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	196,155	73.0	89.5	83.1	9,939 COAL	77,364 TONS	25.20	1,949,585	3,175,038	1.62
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	469	0	0.0	0.0	0.0	0 COAL	0 TONS	25.20	0	0	0.00
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	717	0	0.0	0.0	0.0	0 COAL	0 TONS	25.10	0	0	0.00
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	734	457,431	86.6	97.2	88.0	9,404 COAL	171,382 TONS	25.10	4,301,681	8,377,138	1.83
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	34	2,730	11.2	99.1	62.2	11,934 HEAVY OIL	5,091 BBLS	6.40	32,580	101,099	3.70
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	33	2,146	9.0	99.3	68.5	12,791 HEAVY OIL	4,289 BBLS	6.40	27,449	85,179	3.97
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	9,059	15.7	98.8	66.6	10,793 HEAVY OIL	15,277 BBLS	6.40	97,774	303,404	3.35
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	64	391	0.8	100.0	71.9	16,005 LIGHT OIL	1,079 BBLS	5.80	6,258	29,348	7.51
25	BARTOW	1-4	217	0	0.9	100.0	64.9	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
26	BARTOW	1-4		1,408				14,890 GAS	20,965 MCF	1.00	20,965	55,767	3.96
27	BAYBORO	1-4	232	2,124	1.3	100.0	71.8	13,717 LIGHT OIL	5,023 BBLS	5.80	29,135	136,331	6.42
28	DEBARY	1-10	786	1,225	6.0	100.0	66.5	15,671 LIGHT OIL	3,310 BBLS	5.80	19,197	91,748	7.49
29	DEBARY	1-10		32,682				14,483 GAS	473,333 MCF	1.00	473,333	1,259,067	3.85
30	HIGGINS	1-4	148	0	0.0	100.0	47.1	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		1,550				17,167 GAS	26,609 MCF	1.00	26,609	70,780	4.57
32	HINES	1	505	330,252	90.8	96.5	93.4	6,880 GAS	2,272,134 MCF	1.00	2,272,134	6,043,876	1.83
33	INT CITY	1-10	757	6,582	8.0	100.0	67.6	13,679 LIGHT OIL	15,523 BBLS	5.80	90,035	413,230	6.28
34	INT CITY	1-10		36,751				13,349 GAS	490,589 MCF	1.00	490,589	1,304,967	3.55
35	INT CITY	11	168	3,287	2.7	100.0	72.5	11,481 LIGHT OIL	6,507 BBLS	5.80	37,738	173,205	5.27
36	RIO PINAR	1	18	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37	SUWANNEE	1-3	201	0	0.0	100.0	66.7	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
38	SUWANNEE	1-3		5,946				13,681 GAS	81,347 MCF	1.00	81,347	216,384	3.64
39	TURNER	1-4	200	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
40	UNIV OF FLA.	1	42	29,568	97.8	97.4	100.0	9,352 GAS	276,520 MCF	1.00	276,520	583,216	1.97
41	OTHER - START UP		-	6,446	-	-	-	9,850 LIGHT OIL	10,947 BBLS	5.80	63,493	297,761	4.62
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,945,016	-
43	TOTAL	8,043	2,148,583				9,641				20,713,682	39,527,931	1.84

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: May-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	536,028	94.2	93.4	97.9	10,302	NUCLEAR	5,522,160 MMBTU	1.00	5,522,160	1,822,313	0.34
2 ANCLOTE	1	503	184,594	49.3	95.8	51.3	9,968	HEAVY OIL	287,505 BBLS	6.40	1,840,033	4,634,583	2.51
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	503	172,989	46.2	93.5	53.5	10,039	HEAVY OIL	271,349 BBLS	6.40	1,736,637	4,374,153	2.53
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	115	50,549	59.1	97.7	64.9	10,334	HEAVY OIL	81,621 BBLS	6.40	522,373	1,315,728	2.60
7 BARTOW	2	117	41,321	47.5	97.7	65.6	10,492	HEAVY OIL	67,741 BBLS	6.40	433,540	1,091,979	2.64
8 BARTOW	3	208	82,208	53.1	92.1	62.6	10,088	HEAVY OIL	129,323 BBLS	6.40	827,670	2,084,694	2.54
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	208,779	75.2	88.9	80.5	9,879	COAL	81,846 TONS	25.20	2,062,528	3,353,245	1.61
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	488	143,428	39.5	60.0	69.8	9,773	COAL	55,624 TONS	25.20	1,401,722	2,278,910	1.59
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	714	357,119	67.2	77.9	85.1	9,475	COAL	134,809 TONS	25.10	3,383,703	6,585,413	1.84
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	714	429,466	80.8	97.2	82.2	9,490	COAL	162,376 TONS	25.10	4,075,632	7,932,057	1.85
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	3,535	14.4	98.6	55.5	12,050	HEAVY OIL	6,656 BBLS	6.40	42,597	128,922	3.65
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	32	2,607	11.0	99.0	59.9	13,214	HEAVY OIL	5,383 BBLS	6.40	34,449	104,262	4.00
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	12,391	20.8	98.2	62.2	10,850	HEAVY OIL	21,007 BBLS	6.40	134,442	406,898	3.28
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	1,501	3.5	100.0	86.3	15,947	LIGHT OIL	4,127 BBLS	5.80	23,936	111,181	7.41
25 BARTOW	1-4	187	92	1.7	100.0	61.9	13,143	LIGHT OIL	208 BBLS	5.80	1,209	5,604	6.09
26 BARTOW	1-4		2,224				13,649	GAS	30,355 MCF	1.00	30,355	80,138	3.60
27 BAYBORO	1-4	188	5,365	3.8	100.0	89.9	13,403	LIGHT OIL	12,398 BBLS	5.80	71,907	333,252	6.21
28 DEBARY	1-10	656	5,781	11.7	100.0	75.7	14,577	LIGHT OIL	14,529 BBLS	5.80	84,270	398,973	6.90
29 DEBARY	1-10		51,221				13,925	GAS	713,252 MCF	1.00	713,252	1,882,986	3.68
30 HIGGINS	1-4	128	0	0.0	100.0	61.9	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		4,811				16,282	GAS	78,333 MCF	1.00	78,333	206,798	4.30
32 HINES	1	470	318,478	91.1	96.5	93.6	6,939	GAS	2,209,919 MCF	1.00	2,209,919	5,834,186	1.83
33 INT CITY	1-10	627	6,561	15.5	100.0	99.5	13,558	LIGHT OIL	15,337 BBLS	5.80	88,954	404,281	6.16
34 INT CITY	1-10		65,612				13,238	GAS	868,572 MCF	1.00	868,572	2,293,029	3.49
35 INT CITY	11	143	8,117	7.6	100.0	84.7	11,468	LIGHT OIL	16,049 BBLS	5.80	93,086	423,059	5.21
36 RIO PINAR	1	15	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	162	762	8.1	100.0	78.3	13,111	LIGHT OIL	1,723 BBLS	5.80	9,991	46,697	6.13
38 SUWANNEE	1-3		9,047				13,908	GAS	125,826 MCF	1.00	125,826	332,180	3.67
39 TURNER	1-4	160	253	0.2	100.0	79.1	14,391	LIGHT OIL	628 BBLS	5.80	3,641	17,131	6.77
40 UNIV OF FLA.	1	36	26,209	97.9	97.4	100.0	9,539	GAS	250,008 MCF	1.00	250,008	500,579	1.91
41 OTHER - START UP		-	8,216	-	-	-	9,850	LIGHT OIL	13,956 BBLS	5.80	80,947	375,986	4.58
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	2,260,611	-
43 TOTAL		7,475	2,739,266				9,766				26,751,691	51,619,829	1.88

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jun-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	516,138	93.7	93.5	97.8	10,457	NUCLEAR	5,397,255 MMBTU	1.00	5,397,255	1,781,094	0.35
2 ANCLOTE	1	503	188,617	52.1	95.9	54.5	9,952	HEAVY OIL	293,299 BBLS	6.40	1,877,116	4,683,461	2.47
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	503	190,360	52.6	92.9	56.0	9,946	HEAVY OIL	295,831 BBLS	6.40	1,893,321	4,703,718	2.47
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	115	54,571	65.9	97.6	68.5	10,349	HEAVY OIL	88,243 BBLS	6.40	564,755	1,403,064	2.57
7 BARTOW	2	117	45,378	53.9	97.4	67.0	10,555	HEAVY OIL	74,838 BBLS	6.40	478,965	1,189,928	2.62
8 BARTOW	3	208	85,240	56.9	91.5	62.6	10,120	HEAVY OIL	134,786 BBLS	6.40	862,629	2,143,093	2.51
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	214,782	80.0	88.8	85.3	9,846	COAL	83,911 TONS	25.20	2,114,547	3,435,299	1.60
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	488	231,682	65.9	87.7	73.4	9,768	COAL	89,804 TONS	25.20	2,263,070	3,676,590	1.59
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	714	442,277	86.0	93.0	90.0	9,464	COAL	166,761 TONS	25.10	4,185,710	8,142,956	1.84
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	714	430,397	83.7	97.2	86.1	9,513	COAL	163,122 TONS	25.10	4,094,367	7,965,256	1.85
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	5,467	23.0	98.1	65.0	11,951	HEAVY OIL	10,209 BBLS	6.40	65,338	195,498	3.58
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	32	5,157	22.4	98.3	67.7	12,928	HEAVY OIL	10,417 BBLS	6.40	66,670	199,488	3.87
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	19,772	34.3	97.3	66.1	10,737	HEAVY OIL	33,171 BBLS	6.40	212,292	635,217	3.21
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	2,702	6.5	100.0	83.2	15,871	LIGHT OIL	7,394 BBLS	5.80	42,883	197,929	7.33
25 BARTOW	1-4	187	2,942	6.6	100.0	67.4	14,400	LIGHT OIL	7,304 BBLS	5.80	42,365	195,097	6.63
26 BARTOW	1-4		5,975				15,138	GAS	90,450 MCF	1.00	90,450	243,309	4.07
27 BAYBORO	1-4	188	11,550	8.5	100.0	78.3	13,958	LIGHT OIL	27,796 BBLS	5.80	161,215	742,422	6.43
28 DEBARY	1-10	656	38,258	22.6	100.0	81.5	13,762	LIGHT OIL	90,777 BBLS	5.80	526,507	2,477,304	6.48
29 DEBARY	1-10		68,697				13,734	GAS	943,485 MCF	1.00	943,485	2,537,974	3.69
30 HIGGINS	1-4	128	0	0.0	100.0	64.1	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		9,627				16,857	GAS	162,282 MCF	1.00	162,282	436,539	4.53
32 HINES	1	470	307,975	91.0	96.5	93.9	6,939	GAS	2,137,039 MCF	1.00	2,137,039	5,748,634	1.87
33 INT CITY	1-10	627	19,231	23.7	100.0	67.7	14,029	LIGHT OIL	46,516 BBLS	5.80	269,792	1,218,249	6.33
34 INT CITY	1-10		87,636				14,452	GAS	1,266,515 MCF	1.00	1,266,515	3,406,927	3.89
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	15	100	0.9	100.0	41.7	17,149	LIGHT OIL	296 BBLS	5.80	1,715	7,948	7.95
37 SUWANNEE	1-3	162	4,534	17.2	100.0	78.3	13,150	LIGHT OIL	10,280 BBLS	5.80	59,622	276,934	6.11
38 SUWANNEE	1-3		15,557				13,358	GAS	207,810 MCF	1.00	207,810	559,010	3.59
39 TURNER	1-4	160	2,730	2.4	100.0	52.2	17,113	LIGHT OIL	8,055 BBLS	5.80	46,718	218,449	8.00
40 UNIV OF FLA.	1	36	25,201	97.2	97.5	100.0	9,539	GAS	240,392 MCF	1.00	240,392	513,669	2.04
41 OTHER - START UP		-	9,125	-	-	-	9,850	LIGHT OIL	15,497 BBLS	5.80	89,881	414,848	4.55
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	2,446,421	-
43 TOTAL		7,332	3,041,658				9,983				30,364,703	61,776,329	2.03

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jul-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	785	529,275	93.0	93.5	97.3	10,475 NUCLEAR	5,544,156 MMBTU	1.00	5,544,156	1,829,571	0.35
2	ANCLOTE	1	503	207,576	55.5	95.8	57.3	9,907 HEAVY OIL	321,321 BBLS	6.40	2,056,455	5,083,301	2.45
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	503	205,647	55.0	92.9	58.3	9,893 HEAVY OIL	317,885 BBLS	6.40	2,034,466	5,028,945	2.45
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	115	58,486	68.4	97.5	69.6	10,339 HEAVY OIL	94,482 BBLS	6.40	604,687	1,494,710	2.56
7	BARTOW	2	117	52,257	60.0	97.1	66.7	10,581 HEAVY OIL	86,396 BBLS	6.40	552,931	1,366,777	2.62
8	BARTOW	3	208	95,159	61.5	91.1	64.3	10,125 HEAVY OIL	150,545 BBLS	6.40	963,485	2,381,614	2.50
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	227,458	82.0	88.7	86.6	9,841 COAL	88,826 TONS	25.20	2,238,414	3,634,758	1.60
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	488	253,062	69.7	87.6	76.8	9,732 COAL	97,730 TONS	25.20	2,462,799	3,999,117	1.58
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	714	484,807	91.3	92.8	96.4	9,438 COAL	182,295 TONS	25.10	4,575,608	8,901,473	1.84
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	714	463,350	87.2	97.2	89.3	9,489 COAL	175,168 TONS	25.10	4,396,728	8,553,476	1.85
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	33	8,473	34.5	97.3	67.6	11,921 HEAVY OIL	15,782 BBLS	6.40	101,007	300,968	3.55
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	32	7,666	32.2	97.6	70.3	12,842 HEAVY OIL	15,382 BBLS	6.40	98,447	293,341	3.83
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	25,284	42.5	96.7	68.3	10,698 HEAVY OIL	42,264 BBLS	6.40	270,488	805,970	3.19
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	58	4,162	9.6	100.0	82.0	16,322 LIGHT OIL	11,712 BBLS	5.80	67,932	313,308	7.53
25	BARTOW	1-4	187	3,736	8.9	100.0	76.9	14,349 LIGHT OIL	9,243 BBLS	5.80	53,608	246,689	6.60
26	BARTOW	1-4		8,702				14,206 GAS	123,621 MCF	1.00	123,621	335,012	3.85
27	BAYBORO	1-4	188	13,470	9.6	100.0	77.0	14,027 LIGHT OIL	32,576 BBLS	5.80	188,944	869,467	6.45
28	DEBARY	1-10	656	58,180	28.4	100.0	70.5	13,751 LIGHT OIL	137,937 BBLS	5.80	800,033	3,761,535	6.47
29	DEBARY	1-10		80,527				13,899 GAS	1,119,245 MCF	1.00	1,119,245	3,033,153	3.77
30	HIGGINS	1-4	128	0	0.0	100.0	62.9	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		12,973				17,224 GAS	223,447 MCF	1.00	223,447	605,541	4.67
32	HINES	1	470	281,384	80.5	96.5	83.0	6,990 GAS	1,966,874 MCF	1.00	1,966,874	5,330,229	1.89
33	INT CITY	1-10	627	23,531	27.2	100.0	76.9	14,016 LIGHT OIL	56,864 BBLS	5.80	329,810	1,488,128	6.32
34	INT CITY	1-10		103,510				13,847 GAS	1,433,303 MCF	1.00	1,433,303	3,884,251	3.75
35	INT CITY	11	0	0	0.0	0.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
36	RIO PINAR	1	15	95	0.9	100.0	37.3	17,558 LIGHT OIL	288 BBLS	5.80	1,668	7,725	8.13
37	SUWANNEE	1-3	162	6,604	24.0	100.0	78.1	13,280 LIGHT OIL	15,121 BBLS	5.80	87,701	407,054	6.16
38	SUWANNEE	1-3		22,369				13,895 GAS	310,817 MCF	1.00	310,817	842,315	3.77
39	TURNER	1-4	160	3,968	3.3	100.0	63.6	16,098 LIGHT OIL	11,013 BBLS	5.80	63,877	298,459	7.52
40	UNIV OF FLA.	1	36	26,208	97.8	97.4	100.0	9,539 GAS	249,998 MCF	1.00	249,998	481,920	1.84
41	OTHER - START UP		-	9,833	-	-	-	9,850 LIGHT OIL	16,699 BBLS	5.80	96,855	446,702	4.54
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	2,567,310	-
43	TOTAL		7,332	3,277,752				10,073			33,017,405	68,592,818	2.09

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	765	527,745	92.7	93.5	97.3	10,475 NUCLEAR	5,528,129 MMBTU	1.00	5,528,129	1,824,283	0.35
2	ANCLOTE	1	503	217,365	58.1	95.8	60.2	9,852 HEAVY OIL	334,606 BBLS	6.40	2,141,480	5,276,741	2.43
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	503	212,041	56.7	92.8	59.7	9,865 HEAVY OIL	326,841 BBLS	6.40	2,091,784	5,154,288	2.43
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	115	58,263	68.1	97.5	70.5	10,322 HEAVY OIL	93,967 BBLS	6.40	601,391	1,481,864	2.54
7	BARTOW	2	117	54,726	62.9	97.0	68.2	10,551 HEAVY OIL	90,221 BBLS	6.40	577,414	1,422,784	2.60
8	BARTOW	3	208	96,951	62.6	91.1	65.6	10,089 HEAVY OIL	152,834 BBLS	6.40	978,139	2,410,195	2.49
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	230,569	83.1	88.8	88.4	9,822 COAL	89,867 TONS	25.20	2,264,649	3,676,459	1.59
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	488	259,334	71.4	87.5	78.4	9,715 COAL	99,977 TONS	25.20	2,519,430	4,090,074	1.58
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	714	480,554	90.5	92.9	97.0	9,433 COAL	180,600 TONS	25.10	4,533,066	8,818,709	1.84
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	714	476,709	89.7	97.2	91.2	9,469 COAL	179,839 TONS	25.10	4,513,958	8,781,536	1.84
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	33	9,313	37.9	96.9	65.0	11,956 HEAVY OIL	17,398 BBLS	6.40	111,346	330,907	3.55
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	32	8,578	36.0	97.3	69.8	12,857 HEAVY OIL	17,232 BBLS	6.40	110,287	327,760	3.82
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	27,401	46.0	96.5	69.8	10,678 HEAVY OIL	45,717 BBLS	6.40	292,588	869,535	3.17
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	58	4,729	11.0	100.0	84.5	17,242 LIGHT OIL	14,058 BBLS	5.80	81,537	376,197	7.96
25	BARTOW	1-4	187	7,328	11.3	100.0	72.3	14,815 LIGHT OIL	18,718 BBLS	5.80	108,564	499,770	6.82
26	BARTOW	1-4		8,422				14,990 GAS	126,246 MCF	1.00	126,246	345,913	4.11
27	BAYBORO	1-4	188	16,039	11.5	100.0	73.7	14,203 LIGHT OIL	39,276 BBLS	5.80	227,802	1,048,674	6.54
28	DEBARY	1-10	656	62,771	30.5	100.0	75.5	13,846 LIGHT OIL	149,850 BBLS	5.80	869,127	4,087,895	6.51
29	DEBARY	1-10		85,859				12,938 GAS	1,110,844 MCF	1.00	1,110,844	3,043,712	3.55
30	HIGGINS	1-4	128	0	0.0	100.0	56.8	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		11,990				16,970 GAS	203,470 MCF	1.00	203,470	557,509	4.65
32	HINES	1	470	282,125	80.7	96.5	83.4	6,987 GAS	1,971,207 MCF	1.00	1,971,207	5,401,108	1.91
33	INT CITY	1-10	627	29,344	29.5	100.0	78.0	14,149 LIGHT OIL	71,584 BBLS	5.80	415,188	1,874,074	6.39
34	INT CITY	1-10		108,404				13,442 GAS	1,457,167 MCF	1.00	1,457,167	3,992,636	3.68
35	INT CITY	11	0	0	0.0	0.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
36	RIO PINAR	1	15	245	2.2	100.0	39.8	17,105 LIGHT OIL	723 BBLS	5.80	4,191	19,415	7.92
37	SUWANNEE	1-3	162	8,409	27.7	100.0	77.6	13,199 LIGHT OIL	19,136 BBLS	5.80	110,990	515,340	6.13
38	SUWANNEE	1-3		24,999				13,856 GAS	346,386 MCF	1.00	346,386	949,098	3.80
39	TURNER	1-4	160	8,976	7.5	100.0	62.6	16,306 LIGHT OIL	25,235 BBLS	5.80	146,363	684,119	7.62
40	UNIV OF FLA.	1	36	26,209	97.9	97.4	100.0	9,539 GAS	250,008 MCF	1.00	250,008	525,580	2.01
41	OTHER - START UP		-	10,066	-	-	-	9,850 LIGHT OIL	17,095 BBLS	5.80	99,150	457,458	4.54
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP	-	-	-	2,574,721	-
43	TOTAL		7,332	3,355,464				10,071			33,791,901	71,418,355	2.13

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	517,552	94.0	93.5	97.8	10,479	NUCLEAR	5,423,427 MMBTU	1.00	5,423,427	1,789,731	0.35
2 ANCLOTE	1	503	169,611	46.8	92.8	52.4	10,001	HEAVY OIL	265,044 BBLS	6.40	1,696,280	4,153,235	2.45
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	503	170,905	47.2	93.1	51.4	10,043	HEAVY OIL	268,187 BBLS	6.40	1,716,399	4,202,495	2.46
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	115	51,679	62.4	97.6	66.0	10,417	HEAVY OIL	84,116 BBLS	6.40	538,340	1,318,092	2.55
7 BARTOW	2	117	43,528	51.7	97.5	65.6	10,602	HEAVY OIL	72,107 BBLS	6.40	461,484	1,129,914	2.60
8 BARTOW	3	208	79,900	53.4	91.9	61.6	10,173	HEAVY OIL	127,004 BBLS	6.40	812,823	1,990,146	2.49
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	213,498	79.5	88.9	85.7	9,850	COAL	83,450 TONS	25.20	2,102,936	3,413,098	1.60
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	488	234,673	66.8	87.9	75.8	9,745	COAL	90,750 TONS	25.20	2,286,888	3,711,656	1.58
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	714	470,212	91.5	92.8	96.8	9,434	COAL	176,732 TONS	25.10	4,435,980	8,629,837	1.84
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	714	442,883	86.2	97.2	88.5	9,498	COAL	167,590 TONS	25.10	4,206,503	8,183,408	1.85
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	5,260	22.1	98.1	60.6	12,022	HEAVY OIL	9,881 BBLS	6.40	63,236	186,941	3.55
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	32	4,980	21.6	98.3	66.5	12,984	HEAVY OIL	10,103 BBLS	6.40	64,660	191,152	3.84
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	15,030	26.1	97.9	65.7	10,725	HEAVY OIL	25,187 BBLS	6.40	161,197	476,538	3.17
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	2,544	6.1	100.0	81.2	16,561	LIGHT OIL	7,264 BBLS	5.80	42,131	194,748	7.66
25 BARTOW	1-4	187	2,578	9.5	100.0	71.9	14,463	LIGHT OIL	6,429 BBLS	5.80	37,286	171,964	6.67
26 BARTOW	1-4		10,228				15,333	GAS	156,795 MCF	1.00	156,795	413,939	4.05
27 BAYBORO	1-4	188	8,792	6.5	100.0	77.6	13,988	LIGHT OIL	21,204 BBLS	5.80	122,982	567,204	6.45
28 DEBARY	1-10	656	27,843	18.0	100.0	71.4	13,954	LIGHT OIL	66,986 BBLS	5.80	388,521	1,830,739	6.58
29 DEBARY	1-10		57,359				13,875	GAS	795,856 MCF	1.00	795,856	2,101,060	3.66
30 HIGGINS	1-4	128	0	0.0	100.0	47.9	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		7,611				17,523	GAS	133,368 MCF	1.00	133,368	352,090	4.63
32 HINES	1	470	267,280	79.0	96.5	81.2	7,003	GAS	1,871,762 MCF	1.00	1,871,762	4,941,451	1.85
33 INT CITY	1-10	627	12,870	18.8	100.0	100.2	14,079	LIGHT OIL	31,241 BBLS	5.80	181,197	819,447	6.37
34 INT CITY	1-10		71,971				14,904	GAS	1,072,656 MCF	1.00	1,072,656	2,831,811	3.93
35 INT CITY	11	0	0	0.0	0.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
36 RIO PINAR	1	15	125	1.2	100.0	49.0	16,950	LIGHT OIL	365 BBLS	5.80	2,119	9,834	7.87
37 SUWANNEE	1-3	162	3,356	18.5	100.0	78.2	13,345	LIGHT OIL	7,722 BBLS	5.80	44,786	208,331	6.21
38 SUWANNEE	1-3		18,228				13,848	GAS	252,421 MCF	1.00	252,421	666,392	3.66
39 TURNER	1-4	160	2,453	2.1	100.0	63.0	16,212	LIGHT OIL	6,857 BBLS	5.80	39,768	186,224	7.59
40 UNIV OF FLA.	1	36	25,200	97.2	97.5	100.0	9,539	GAS	240,383 MCF	1.00	240,383	482,284	1.91
41 OTHER - START UP		-	8,841	-	-	-	9,850	LIGHT OIL	15,014 BBLS	5.80	87,084	402,538	4.55
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	2,389,340	-
43 TOTAL		7,332	2,946,986				9,990				29,439,267	57,945,639	1.97

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	765	533,100	93.7		97.3	10,305	NUCLEAR	5,493,596 MMBTU	1.00	5,493,596	1,812,887	0.34
2 ANCLOTE	1	503	81,143	21.7	78.5	42.8	10,169	HEAVY OIL	128,929 BBLS	6.40	825,143	2,097,669	2.59
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	503	89,347	23.9	82.8	42.0	10,381	HEAVY OIL	144,924 BBLS	6.40	927,511	2,357,907	2.64
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	115	32,789	38.3	98.4	60.2	10,455	HEAVY OIL	53,564 BBLS	6.40	342,809	871,485	2.66
7 BARTOW	2	117	20,999	24.1	98.8	67.0	10,470	HEAVY OIL	34,353 BBLS	6.40	219,860	558,924	2.66
8 BARTOW	3	208	53,243	34.4	94.3	55.9	10,326	HEAVY OIL	85,904 BBLS	6.40	549,787	1,397,662	2.63
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	204,800	73.8	89.3	82.3	9,820	COAL	79,807 TONS	25.20	2,011,136	3,263,308	1.59
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	488	209,026	57.6	87.9	65.2	9,834	COAL	81,570 TONS	25.20	2,055,562	3,335,394	1.60
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	714	457,288	86.1	92.9	91.6	9,411	COAL	171,456 TONS	25.10	4,303,537	8,370,466	1.83
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	714	443,851	83.6	97.2	84.9	9,464	COAL	167,355 TONS	25.10	4,200,606	8,170,262	1.84
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	33	1,262	5.1	99.5	51.7	12,135	HEAVY OIL	2,393 BBLS	6.40	15,314	46,709	3.70
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	32	766	3.2	99.7	57.0	13,476	HEAVY OIL	1,613 BBLS	6.40	10,323	31,484	4.11
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	4,242	7.1	99.4	62.4	10,854	HEAVY OIL	7,194 BBLS	6.40	46,043	140,430	3.31
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	58	1,007	2.3	100.0	77.2	16,825	LIGHT OIL	2,921 BBLS	5.80	16,943	79,777	7.92
25 BARTOW	1-4	187	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
26 BARTOW	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
27 BAYBORO	1-4	188	3,728	2.7	100.0	71.5	14,455	LIGHT OIL	9,291 BBLS	5.80	53,888	253,182	6.79
28 DEBARY	1-10	656	720	4.3	100.0	74.7	16,377	LIGHT OIL	2,033 BBLS	5.80	11,791	56,579	7.86
29 DEBARY	1-10		20,289				13,881	GAS	281,226 MCF	1.00	281,226	728,375	3.59
30 HIGGINS	1-4	128	0	0.0	100.0	32.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		1,792				16,731	GAS	29,982 MCF	1.00	29,982	77,653	4.33
32 HINES	1	470	251,693	72.0	96.5	74.0	6,984	GAS	1,757,824 MCF	1.00	1,757,824	4,552,764	1.81
33 INT CITY	1-10	627	3,381	7.4	100.0	82.1	14,547	LIGHT OIL	8,480 BBLS	5.80	49,183	226,668	6.70
34 INT CITY	1-10		31,160				13,541	GAS	421,938 MCF	1.00	421,938	1,092,818	3.51
35 INT CITY	11	168	1,301	1.0	100.0	70.4	11,509	LIGHT OIL	2,582 BBLS	5.80	14,973	69,006	5.30
36 RIO PINAR	1	15	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 SUWANNEE	1-3	162	178	2.2	100.0	71.7	12,908	LIGHT OIL	396 BBLS	5.80	2,297	10,884	6.11
38 SUWANNEE	1-3		2,456				14,313	GAS	35,153 MCF	1.00	35,153	91,046	3.71
39 TURNER	1-4	160	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
40 UNIV OF FLA.	1	36	26,064	97.3	97.4	100.0	9,542	GAS	248,703 MCF	1.00	248,703	446,031	1.71
41 OTHER - START UP		-	7,449	-	-	-	9,850	LIGHT OIL	12,650 BBLS	5.80	73,373	345,484	4.64
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	2,065,743	-
43 TOTAL		7,500	2,483,074				9,665				23,998,500	42,550,595	1.71

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	782	525,665	93.4	93.5	98.1	10,338	NUCLEAR	5,434,325 MMBTU	1.00	5,434,325	1,793,327	0.34
2 ANCLOTE	1	517	91,697	24.6	97.7	46.9	10,028	HEAVY OIL	143,678 BBLS	6.40	919,538	2,369,246	2.58
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	517	9,214	2.5	19.5	41.4	10,316	HEAVY OIL	14,852 BBLS	6.40	95,052	244,906	2.66
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	117	26,920	32.0	78.7	61.4	10,399	HEAVY OIL	43,741 BBLS	6.40	279,941	721,286	2.68
7 BARTOW	2	119	17,623	20.6	99.0	64.7	10,492	HEAVY OIL	28,891 BBLS	6.40	184,901	476,408	2.70
8 BARTOW	3	213	51,326	33.5	94.8	60.1	10,236	HEAVY OIL	82,090 BBLS	6.40	525,373	1,353,656	2.64
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	193,648	72.1	89.0	78.1	9,973	COAL	76,637 TONS	25.20	1,931,252	3,133,685	1.62
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	469	211,222	62.6	88.2	72.8	9,770	COAL	81,890 TONS	25.20	2,063,639	3,348,500	1.59
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	717	435,947	84.4	92.9	90.5	9,403	COAL	163,315 TONS	25.10	4,099,210	7,973,044	1.83
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	734	335,768	63.5	74.5	84.2	9,459	COAL	126,535 TONS	25.10	3,176,030	6,177,441	1.84
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	34	1,140	4.7	99.6	68.4	11,861	HEAVY OIL	2,113 BBLS	6.40	13,522	41,705	3.66
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	33	1,029	4.3	99.7	70.9	12,705	HEAVY OIL	2,043 BBLS	6.40	13,073	40,323	3.92
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	5,304	9.2	99.3	69.8	10,765	HEAVY OIL	8,921 BBLS	6.40	57,098	176,110	3.32
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	64	563	1.2	100.0	62.8	16,331	LIGHT OIL	1,585 BBLS	5.80	9,194	43,435	7.71
25 BARTOW	1-4	217	293	1.3	100.0	54.5	16,762	LIGHT OIL	847 BBLS	5.80	4,911	23,151	7.90
26 BARTOW	1-4		1,778				14,863	GAS	26,426 MCF	1.00	26,426	71,351	4.01
27 BAYBORO	1-4	232	3,232	1.9	100.0	74.3	13,622	LIGHT OIL	7,591 BBLS	5.80	44,026	207,531	6.42
28 DEBARY	1-10	786	4,584	4.6	100.0	64.7	14,352	LIGHT OIL	11,343 BBLS	5.80	65,790	316,697	6.91
29 DEBARY	1-10		21,361				13,234	GAS	282,691 MCF	1.00	282,691	763,267	3.57
30 HIGGINS	1-4	148	0	0.0	100.0	47.6	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		3,926				16,731	GAS	65,686 MCF	1.00	65,686	177,352	4.52
32 HINES	1	505	138,547	38.1	51.5	74.3	6,991	GAS	968,582 MCF	1.00	968,582	2,615,172	1.89
33 INT CITY	1-10	757	8,359	6.8	100.0	71.3	13,716	LIGHT OIL	19,768 BBLS	5.80	114,652	530,167	6.34
34 INT CITY	1-10		28,611				13,358	GAS	382,186 MCF	1.00	382,186	1,031,901	3.61
35 INT CITY	11	168	5,525	4.6	100.0	76.5	11,439	LIGHT OIL	10,897 BBLS	5.80	63,200	292,248	5.29
36 RIO PINAR	1	18	20	0.2	100.0	27.8	17,305	LIGHT OIL	60 BBLS	5.80	346	1,642	8.21
37 SUWANNEE	1-3	201	0	0.0	100.0	71.2	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
38 SUWANNEE	1-3		3,769				13,391	GAS	50,471 MCF	1.00	50,471	136,271	3.62
39 TURNER	1-4	200	140	0.1	100.0	26.3	15,337	LIGHT OIL	370 BBLS	5.80	2,147	10,273	7.34
40 UNIV OF FLA.	1	42	25,788	85.3	84.4	100.0	9,353	GAS	241,195 MCF	1.00	241,195	454,729	1.76
41 OTHER - START UP		-	6,478	-	-	-	9,850	LIGHT OIL	11,001 BBLS	5.80	63,808	301,439	4.65
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	1,958,137	-
43 TOTAL		8,043	2,159,477				9,807				21,178,264	36,784,402	1.70

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-00

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	782	543,487	93.4	93.4	97.1	10,275 NUCLEAR	5,584,329 MMBTU	1.00	5,584,329	1,842,829	0.34
2	ANCLOTE	1	517	80,318	20.9	98.0	45.0	10,058 HEAVY OIL	126,225 BBLS	6.40	807,838	2,139,510	2.66
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	517	67,592	17.6	97.1	45.1	10,146 HEAVY OIL	107,154 BBLS	6.40	685,788	1,816,268	2.69
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	117	20,451	23.5	73.2	60.3	10,379 HEAVY OIL	33,166 BBLS	6.40	212,261	562,160	2.75
7	BARTOW	2	119	7,859	8.9	54.4	71.8	10,325 HEAVY OIL	12,679 BBLS	6.40	81,144	214,905	2.73
8	BARTOW	3	213	39,002	24.6	73.4	56.3	10,279 HEAVY OIL	62,641 BBLS	6.40	400,902	1,061,763	2.72
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	373	195,663	70.5	89.0	76.2	9,942 COAL	77,194 TONS	25.20	1,945,282	3,156,451	1.61
11	CRYSTAL RIVER	1		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
12	CRYSTAL RIVER	2	469	198,966	57.0	89.0	70.7	9,771 COAL	77,147 TONS	25.20	1,944,097	3,154,528	1.59
13	CRYSTAL RIVER	2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
14	CRYSTAL RIVER	4	717	458,654	86.0	92.8	90.9	9,366 COAL	171,146 TONS	25.10	4,295,753	8,355,326	1.82
15	CRYSTAL RIVER	4		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
16	CRYSTAL RIVER	5	734	450,108	82.4	97.3	87.0	9,369 COAL	168,010 TONS	25.10	4,217,062	8,202,269	1.82
17	CRYSTAL RIVER	5		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
18	SUWANNEE	1	34	1,215	4.8	99.6	56.7	11,941 HEAVY OIL	2,267 BBLS	6.40	14,508	45,792	3.77
19	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
20	SUWANNEE	2	33	1,051	4.3	99.6	61.2	12,996 HEAVY OIL	2,134 BBLS	6.40	13,659	43,111	4.10
21	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
22	SUWANNEE	3	80	3,417	5.7	99.5	62.8	10,588 HEAVY OIL	5,652 BBLS	6.40	36,172	114,169	3.34
23	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
24	AVON PARK	1-2	64	323	0.7	100.0	59.4	17,100 LIGHT OIL	952 BBLS	5.80	5,523	26,340	8.15
25	BARTOW	1-4	217	0	0.8	100.0	61.5	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
26	BARTOW	1-4		1,235				15,921 GAS	19,662 MCF	1.00	19,662	55,251	4.47
27	BAYBORO	1-4	232	2,961	1.7	100.0	74.0	14,531 LIGHT OIL	7,418 BBLS	5.80	43,026	204,746	6.91
28	DEBARY	1-10	786	2,695	2.2	100.0	51.6	16,064 LIGHT OIL	7,464 BBLS	5.80	43,292	210,342	7.80
29	DEBARY	1-10		10,444				13,793 GAS	144,054 MCF	1.00	144,054	404,792	3.88
30	HIGGINS	1-4	148	0	0.0	100.0	28.9	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
31	HIGGINS	1-4		1,692				16,931 GAS	28,647 MCF	1.00	28,647	80,499	4.76
32	HINES	1	505	252,717	67.3	100.0	69.1	7,002 GAS	1,769,524 MCF	1.00	1,769,524	4,972,364	1.97
33	INT CITY	1-14	1,054	5,338	5.5	100.0	48.2	14,716 LIGHT OIL	13,544 BBLS	5.80	78,554	366,766	6.87
34	INT CITY	1-14		37,451				13,473 GAS	504,577 MCF	1.00	504,577	1,417,862	3.79
35	INT CITY	11	168	3,056	2.4	100.0	75.8	11,194 LIGHT OIL	5,898 BBLS	5.80	34,209	159,720	5.23
36	RIO PINAR	1	18	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37	SUWANNEE	1-3	201	339	2.1	100.0	59.8	15,885 LIGHT OIL	928 BBLS	5.80	5,385	25,839	7.62
38	SUWANNEE	1-3		2,744				13,893 GAS	38,122 MCF	1.00	38,122	107,124	3.90
39	TURNER	1-4	200	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
40	UNIV OF FLA.	1	42	30,408	97.3	97.4	100.0	9,352 GAS	284,376 MCF	1.00	284,376	620,616	2.04
41	OTHER - START UP		-	7,279	-	-	-	9,850 LIGHT OIL	12,362 BBLS	5.80	71,698	341,926	4.70
42	OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	1,951,710	-
43	TOTAL	8,340	2,426,465				9,606				23,309,447	41,654,977	1.72

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Jan-00 THROUGH Dec-00

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	774	6,348,026	93.4	93.5	97.5	10,353	NUCLEAR	65,722,728 MMBTU	1.00	65,722,728	21,688,500	0.34
2 ANCLOTE	1	510	1,718,418	38.4	92.9	51.4	9,956	HEAVY OIL	2,673,346 BBLS	6.40	17,109,411	43,647,656	2.54
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	510	1,596,954	35.6	85.2	53.0	9,982	HEAVY OIL	2,490,651 BBLS	6.40	15,940,166	40,613,445	2.54
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	116	481,597	47.3	92.4	65.9	10,340	HEAVY OIL	778,055 BBLS	6.40	4,979,551	12,690,089	2.64
7 BARTOW	2	118	380,741	36.7	94.5	66.7	10,506	HEAVY OIL	624,986 BBLS	6.40	3,999,907	10,153,792	2.67
8 BARTOW	3	211	743,655	40.2	84.3	60.7	10,161	HEAVY OIL	1,180,638 BBLS	6.40	7,556,085	19,161,472	2.58
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	373	2,442,650	74.6	89.1	81.5	9,889	COAL	958,564 TONS	25.20	24,155,810	39,296,309	1.61
11 CRYSTAL RIVER	1		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
12 CRYSTAL RIVER	2	479	2,179,695	51.9	75.3	70.4	9,843	COAL	851,337 TONS	25.20	21,453,684	34,888,283	1.60
13 CRYSTAL RIVER	2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
14 CRYSTAL RIVER	4	716	4,366,331	69.5	76.9	89.1	9,440	COAL	1,642,122 TONS	25.10	41,217,264	80,222,871	1.84
15 CRYSTAL RIVER	4		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
16 CRYSTAL RIVER	5	724	5,402,854	85.0	95.3	88.7	9,419	COAL	2,027,431 TONS	25.10	50,888,512	99,072,287	1.83
17 CRYSTAL RIVER	5		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
18 SUWANNEE	1	34	43,876	14.9	98.7	62.4	11,954	HEAVY OIL	81,954 BBLS	6.40	524,507	1,588,241	3.62
19 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
20 SUWANNEE	2	33	39,275	13.8	98.9	66.7	12,909	HEAVY OIL	79,219 BBLS	6.40	507,000	1,535,247	3.91
21 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
22 SUWANNEE	3	80	139,850	19.9	98.4	66.3	10,711	HEAVY OIL	234,062 BBLS	6.40	1,497,994	4,540,536	3.25
23 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
24 AVON PARK	1-2	61	20,836	3.9	100.0	76.1	16,621	LIGHT OIL	59,709 BBLS	5.80	346,312	1,605,522	7.71
25 BARTOW	1-4	202	21,953	4.3	100.0	66.7	14,675	LIGHT OIL	55,545 BBLS	5.80	322,164	1,488,587	6.78
26 BARTOW	1-4		54,233				14,853	GAS	805,502 MCF	1.00	805,502	2,208,039	4.07
27 BAYBORO	1-4	210	82,177	4.5	100.0	69.9	14,257	LIGHT OIL	201,995 BBLS	5.80	1,171,572	5,425,084	6.60
28 DEBARY	1-10	721	235,534	11.7	100.0	67.7	13,875	LIGHT OIL	563,462 BBLS	5.80	3,268,081	15,414,358	6.54
29 DEBARY	1-10		506,340				13,635	GAS	6,903,926 MCF	1.00	6,903,926	18,733,475	3.70
30 HIGGINS	1-4	138	0	0.0	100.0	48.9	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
31 HIGGINS	1-4		65,074				17,010	GAS	1,106,920 MCF	1.00	1,106,920	3,009,203	4.62
32 HINES	1	488	3,212,982	75.0	89.4	83.7	6,942	GAS	22,305,495 MCF	1.00	22,305,495	61,102,351	1.90
33 INT CITY	1-14	717	146,695	13.1	100.0	70.5	14,172	LIGHT OIL	358,444 BBLS	5.80	2,078,973	9,448,679	6.44
34 INT CITY	1-14		675,058				13,756	GAS	9,285,844 MCF	1.00	9,285,844	25,237,377	3.74
35 INT CITY	11	165	45,375	3.1	66.7	76.4	11,353	LIGHT OIL	88,817 BBLS	5.80	515,141	2,358,066	5.20
36 RIO PINAR	1	17	845	0.6	100.0	38.2	17,260	LIGHT OIL	2,515 BBLS	5.80	14,585	67,876	8.03
37 SUWANNEE	1-3	182	27,735	9.5	100.0	70.1	13,447	LIGHT OIL	64,302 BBLS	5.80	372,954	1,735,280	6.26
38 SUWANNEE	1-3		123,895				13,767	GAS	1,705,603 MCF	1.00	1,705,603	4,637,871	3.74
39 TURNER	1-4	180	23,852	1.5	100.0	52.2	16,470	LIGHT OIL	67,732 BBLS	5.80	392,844	1,841,516	7.72
40 UNIV OF FLA.	1	39	330,357	96.4	96.3	99.9	9,440	GAS	3,118,605 MCF	1.00	3,118,605	6,460,339	1.96
41 OTHER - START UP		-	94,653	-	-	-	9,850	LIGHT OIL	160,747 BBLS	5.80	932,332	4,343,191	4.59
42 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	26,099,673	-
43 TOTAL		7,793	31,551,516				9,832				310,199,475	600,315,215	1.90

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

			Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Subtotal
	HEAVY OIL								
1	PURCHASES:								
2	UNITS	BBL	321,903	272,329	802,797	812,881	870,585	940,794	4,021,289
3	UNIT COST	$/BBL	17.25	17.34	17.48	16.61	16.12	15.90	16.61
4	AMOUNT	$	5,552,823	4,722,179	14,032,898	13,501,960	14,033,823	14,958,630	66,802,313
5	BURNED:								
6	UNITS	BBL	321,903	272,329	802,797	812,881	870,585	940,794	4,021,289
7	UNIT COST	$/BBL	17.38	17.50	17.58	16.71	16.24	16.09	16.74
8	AMOUNT	$	5,595,424	4,766,563	14,109,909	13,582,094	14,141,219	15,133,468	67,328,677
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	17.50	17.46	17.47	17.04	16.56	16.20	
12	AMOUNT	$	14,000,000	13,967,493	13,975,761	13,629,134	13,247,079	12,962,225	
13	DAYS SUPPLY:		77	85	31	30	28	26	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	96,803	93,532	137,084	42,389	78,965	213,913	662,678
16	UNIT COST	$/BBL	26.65	27.07	27.36	27.23	26.97	26.80	26.98
17	AMOUNT	$	2,579,802	2,531,922	3,750,630	1,154,252	2,129,425	5,732,881	17,878,914
18	BURNED:								
19	UNITS	BBL	96,803	93,532	137,084	42,389	78,965	213,913	662,678
20	UNIT COST	$/BBL	26.55	26.98	27.22	26.93	26.80	26.88	26.91
21	AMOUNT	$	2,570,259	2,523,166	3,730,888	1,141,623	2,116,164	5,749,182	17,831,282
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	26.55	26.63	26.77	26.80	26.83	26.82	
25	AMOUNT	$	14,602,500	14,644,068	14,724,659	14,742,680	14,754,081	14,750,138	
26	DAYS SUPPLY:		176	171	124	389	216	77	
	COAL								
27	PURCHASES:								
28	UNITS	TON	469,000	438,000	464,000	438,000	469,000	438,000	2,716,000
29	UNIT COST	$/TON	45.88	45.96	45.85	45.96	45.88	45.96	45.91
30	AMOUNT	$	21,517,720	20,130,480	21,274,400	20,130,480	21,517,720	20,130,480	124,701,280
31	BURNED:								
32	UNITS	TON	450,688	446,304	340,576	248,746	434,656	503,598	2,424,567
33	UNIT COST	$/TON	46.88	46.70	45.66	46.44	46.36	46.11	46.38
34	AMOUNT	$	21,126,671	20,844,585	15,552,316	11,552,176	20,149,625	23,220,102	112,445,475
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	541,696	665,120	854,374	888,719	823,121	
37	UNIT COST	$/TON	46.88	46.47	46.18	46.10	46.02	46.00	
38	AMOUNT	$	25,782,075	25,172,717	30,717,963	39,382,454	40,897,850	37,863,088	
39	DAYS SUPPLY:		36	36	44	59	59	56	
	GAS								
40	BURNED:								
41	UNITS	MCF	3,049,891	3,023,432	3,195,939	3,641,497	4,276,264	5,047,973	22,234,997
42	UNIT COST	$/MCF	3.57	3.48	3.38	3.15	3.13	3.15	3.28
43	AMOUNT	$	10,885,000	10,509,089	10,810,971	11,479,072	13,390,508	15,892,483	72,967,122
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,588,821	5,173,102	5,660,807	5,372,622	5,522,160	5,397,255	32,714,767
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
47	AMOUNT	$	1,844,311	1,707,124	1,868,066	1,772,965	1,822,313	1,781,094	10,795,873

FLORIDA POWER CORPORATION
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

	HEAVY OIL		Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
1	PURCHASES:								
2	UNITS	BBL	1,044,057	1,078,817	861,628	458,873	326,328	351,918	8,142,910
3	UNIT COST	$/BBL	15.82	15.77	15.67	16.27	16.49	16.95	16.29
4	AMOUNT	$	16,516,984	17,012,945	13,501,708	7,465,870	5,381,141	5,965,004	132,645,965
5	BURNED:								
6	UNITS	BBL	1,044,057	1,078,817	861,628	458,873	326,328	351,918	8,142,910
7	UNIT COST	$/BBL	16.05	16.01	15.84	16.35	16.62	17.04	16.45
8	AMOUNT	$	16,755,626	17,274,073	13,648,513	7,502,270	5,423,641	5,997,677	133,930,478
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	15.99	15.86	15.76	15.95	16.10	16.36	
12	AMOUNT	$	12,788,848	12,689,599	12,609,961	12,757,960	12,883,713	13,090,323	
13	DAYS SUPPLY:		24	23	28	54	74	70	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	291,453	355,675	163,082	38,353	63,461	48,567	1,623,269
16	UNIT COST	$/BBL	26.78	26.79	26.84	27.34	27.43	27.69	26.94
17	AMOUNT	$	7,806,116	9,528,524	4,377,112	1,048,579	1,740,744	1,344,818	43,723,806
18	BURNED:								
19	UNITS	BBL	291,453	355,675	163,082	38,353	63,461	48,567	1,623,269
20	UNIT COST	$/BBL	26.90	26.89	26.93	27.16	27.21	27.50	26.94
21	AMOUNT	$	7,839,066	9,562,942	4,391,028	1,041,579	1,726,583	1,335,679	43,728,159
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	26.81	26.80	26.81	26.84	26.90	26.97	
25	AMOUNT	$	14,742,816	14,739,550	14,744,686	14,763,740	14,797,129	14,832,211	
26	DAYS SUPPLY:		58	48	101	445	260	351	
	COAL								
27	PURCHASES:								
28	UNITS	TON	469,000	448,000	469,000	473,000	469,000	456,000	5,500,000
29	UNIT COST	$/TON	45.88	46.02	45.88	46.17	45.88	45.93	45.94
30	AMOUNT	$	21,517,720	20,616,960	21,517,720	21,838,410	21,517,720	20,944,080	252,653,890
31	BURNED:								
32	UNITS	TON	544,020	550,284	518,521	500,187	448,378	493,496	5,479,453
33	UNIT COST	$/TON	46.12	46.10	46.17	46.26	46.02	46.34	46.26
34	AMOUNT	$	25,088,823	25,366,779	23,937,998	23,139,429	20,632,670	22,868,575	253,479,749
35	ENDING INVENTORY:								
36	UNITS	TON	748,101	645,818	596,296	569,109	589,731	552,235	
37	UNIT COST	$/TON	45.96	45.98	45.94	46.04	45.97	45.95	
38	AMOUNT	$	34,379,794	29,694,704	27,392,618	26,202,104	27,108,787	25,375,991	
39	DAYS SUPPLY:		49	45	38	37	38	38	
	GAS								
40	BURNED:								
41	UNITS	MCF	5,427,305	5,466,328	4,523,241	2,774,825	2,017,237	2,788,964	45,231,896
42	UNIT COST	$/MCF	3.15	3.18	3.13	3.26	3.57	3.45	3.26
43	AMOUNT	$	17,079,731	17,390,278	14,178,369	9,054,430	7,208,180	9,610,218	147,488,328
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,544,156	5,528,129	5,423,427	5,493,596	5,434,325	5,584,329	65,722,728
46	UNIT COST	$/MMBTU	0.33	0.33	0.33	0.33	0.33	0.33	0.33
47	AMOUNT	$	1,829,571	1,824,283	1,789,731	1,812,887	1,793,327	1,842,829	21,688,500

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				KWH		C/KWH				REFUNDABLE
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	GAIN ON POWER SALES $
Jan-00	ECONSALE	--	92,536,100		92,536,100	1.766	2.066	1,633,821	1,911,429	222,087
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	83,063,000		83,063,000	2.482	2.482	2,061,439	2,061,439	0
	TOTAL		175,599,100		175,599,100	2.104	2.262	3,695,260	3,972,868	222,087
Feb-00	ECONSALE	--	167,845,400		167,845,400	1.682	2.382	2,823,616	3,998,534	939,934
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	144,465,000		144,465,000	2.823	2.823	4,078,045	4,078,045	0
	TOTAL		312,310,400		312,310,400	2.210	2.586	6,901,661	8,076,579	939,934
Mar-00	ECONSALE	--	184,196,300		184,196,300	1.736	2.136	3,197,872	3,934,657	589,428
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	139,503,000		139,503,000	2.977	2.977	4,152,431	4,152,431	0
	TOTAL		323,699,300		323,699,300	2.271	2.498	7,350,303	8,087,088	589,428
Apr-00	ECONSALE	--	75,422,500		75,422,500	2.177	2.377	1,642,243	1,793,088	120,676
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	109,201,000		109,201,000	2.563	2.563	2,798,330	2,798,330	0
	TOTAL		184,623,500		184,623,500	2.405	2.487	4,440,573	4,591,418	120,676
May-00	ECONSALE	--	53,520,700		53,520,700	2.283	2.783	1,222,102	1,489,706	214,083
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	172,868,000		172,868,000	1.844	1.844	3,186,959	3,186,959	0
	TOTAL		226,388,700		226,388,700	1.948	2.066	4,409,061	4,676,665	214,083
Jun-00	ECONSALE	--	107,692,800		107,692,800	2.837	4.337	3,054,998	4,670,390	1,292,314
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	108,487,000		108,487,000	1.818	1.818	1,972,175	1,972,175	0
	TOTAL		216,179,800		216,179,800	2.325	3.073	5,027,173	6,642,565	1,292,314

FLORIDA POWER CORPORATION
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-00	ECONSALE	--	138,786,500		138,786,500	3.679	5.979	5,105,994	8,298,084	2,553,672
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	193,828,000		193,828,000	2.072	2.072	4,015,284	4,015,284	0
	TOTAL		332,614,500		332,614,500	2.742	3.702	9,121,278	12,313,368	2,553,672
Aug-00	ECONSALE	--	139,401,000		139,401,000	3.390	5.690	4,725,020	7,931,243	2,564,978
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	232,055,000		232,055,000	2.366	2.366	5,491,501	5,491,501	0
	TOTAL		371,456,000		371,456,000	2.750	3.614	10,216,521	13,422,744	2,564,978
Sep-00	ECONSALE	--	125,069,200		125,069,200	2.818	3.818	3,525,068	4,775,760	1,000,554
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	253,452,000		253,452,000	2.635	2.635	6,678,754	6,678,754	0
	TOTAL		378,521,200		378,521,200	2.696	3.026	10,203,822	11,454,514	1,000,554
Oct-00	ECONSALE	--	111,651,400		111,651,400	2.021	2.621	2,256,789	2,926,697	535,927
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	232,510,000		232,510,000	2.561	2.561	5,953,887	5,953,887	0
	TOTAL		344,161,400		344,161,400	2.386	2.580	8,210,676	8,880,584	535,927
Nov-00	ECONSALE	--	128,086,200		128,086,200	1.677	1.877	2,147,657	2,403,829	204,938
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	123,090,000		123,090,000	2.103	2.103	2,588,346	2,588,346	0
	TOTAL		251,176,200		251,176,200	1.886	1.988	4,736,003	4,992,175	204,938
Dec-00	ECONSALE	--	120,792,700		120,792,700	1.666	1.966	2,012,260	2,374,638	289,902
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	135,537,000		135,537,000	2.199	2.199	2,980,536	2,980,536	0
	TOTAL		256,329,700		256,329,700	1.948	2.089	4,992,796	5,355,174	289,902
Jan-00	ECONSALE	--	1,445,000,800		1,445,000,800	2.308	3.219	33,347,440	46,508,055	10,528,492
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-00	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,928,059,000		1,928,059,000	2.384	2.384	45,957,687	45,957,687	0
	TOTAL		3,373,059,800		3,373,059,800	2.351	2.741	79,305,127	92,465,742	10,528,492

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	5,416,300			5,416,300	2.700	2.700	146,241
	UPS PURCHASE	UPS	201,120,000			201,120,000	1.390	1.390	2,795,574
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		206,536,300	0	0	206,536,300	1.424	1.424	2,941,815
Feb-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	5,598,600			5,598,600	2.700	2.700	151,162
	UPS PURCHASE	UPS	188,152,000			188,152,000	1.390	1.390	2,615,319
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		193,750,600	0	0	193,750,600	1.428	1.428	2,766,481
Mar-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	14,972,200			14,972,200	2.700	2.700	404,248
	UPS PURCHASE	UPS	201,126,000			201,126,000	1.390	1.390	2,795,657
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		216,098,200	0	0	216,098,200	1.481	1.481	3,199,905
Apr-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	9,436,300			9,436,300	2.700	2.700	254,781
	UPS PURCHASE	UPS	194,586,700			194,586,700	1.390	1.390	2,704,761
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		204,023,000	0	0	204,023,000	1.451	1.451	2,959,542
May-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	12,082,300			12,082,300	2.700	2.700	326,222
	UPS PURCHASE	UPS	201,098,000			201,098,000	1.390	1.390	2,795,268
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		213,180,300	0	0	213,180,300	1.464	1.464	3,121,490
Jun-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	14,344,700			14,344,700	2.700	2.700	387,308
	UPS PURCHASE	UPS	194,640,000			194,640,000	1.390	1.390	2,705,501
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		208,984,700	0	0	208,984,700	1.480	1.480	3,092,809

FLORIDA POWER CORPORATION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	16,038,100			16,038,100	2.700	2.700	433,028
	UPS PURCHASE	UPS	201,128,000			201,128,000	1.390	1.390	2,795,685
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		217,166,100	0	0	217,166,100	1.487	1.487	3,228,713
Aug-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	17,745,200			17,745,200	2.700	2.700	479,120
	UPS PURCHASE	UPS	201,128,000			201,128,000	1.390	1.390	2,795,685
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		218,873,200	0	0	218,873,200	1.496	1.496	3,274,805
Sep-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	11,476,800			11,476,800	2.700	2.700	309,873
	UPS PURCHASE	UPS	194,640,000			194,640,000	1.390	1.390	2,705,502
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		206,116,800	0	0	206,116,800	1.463	1.463	3,015,375
Oct-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	7,852,500			7,852,500	2.700	2.700	212,016
	UPS PURCHASE	UPS	200,971,200			200,971,200	1.390	1.390	2,793,506
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		208,823,700	0	0	208,823,700	1.439	1.439	3,005,522
Nov-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	8,392,400			8,392,400	2.700	2.700	226,594
	UPS PURCHASE	UPS	194,639,000			194,639,000	1.390	1.390	2,705,487
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		203,031,400	0	0	203,031,400	1.444	1.444	2,932,081
Dec-00	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	6,587,200			6,587,200	2.700	2.700	177,855
	UPS PURCHASE	UPS	201,117,000			201,117,000	1.390	1.390	2,795,532
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		207,704,200	0	0	207,704,200	1.432	1.432	2,973,387
Jan-00	EMERGENCY	A&B	0			0	0.000	0.000	0
THRU	TECO	--	129,942,600			129,942,600	2.700	2.700	3,508,448
Dec-00	UPS PURCHASE	UPS	2,374,345,900			2,374,345,900	1.390	1.390	33,003,477
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		2,504,288,500	0	0	2,504,288,500	1.458	1.458	36,511,925

FLORIDA POWER CORPORATION
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-00	QUAL. FACILITIES	COGEN	542,291,400			542,291,400	1.879	5.931	10,187,502
Feb-00	QUAL. FACILITIES	COGEN	520,597,500			520,597,500	1.878	5.930	9,774,500
Mar-00	QUAL. FACILITIES	COGEN	508,648,800			508,648,800	1.899	5.952	9,660,564
Apr-00	QUAL. FACILITIES	COGEN	496,612,600			496,612,600	1.913	5.966	9,500,330
May-00	QUAL. FACILITIES	COGEN	581,953,600			581,953,600	1.909	5.961	11,107,002
Jun-00	QUAL. FACILITIES	COGEN	607,005,900			607,005,900	1.914	5.967	11,617,467
Jul-00	QUAL. FACILITIES	COGEN	625,354,600			625,354,600	1.921	5.974	12,013,551
Aug-00	QUAL. FACILITIES	COGEN	635,900,100			635,900,100	1.927	5.979	12,250,854
Sep-00	QUAL. FACILITIES	COGEN	603,381,800			603,381,800	1.911	5.963	11,528,325
Oct-00	QUAL. FACILITIES	COGEN	528,637,100			528,637,100	1.890	5.943	9,992,217
Nov-00	QUAL. FACILITIES	COGEN	495,514,200			495,514,200	1.895	5.948	9,390,306
Dec-00	QUAL. FACILITIES	COGEN	561,830,600			561,830,600	1.871	5.924	10,513,153
TOTAL	QUAL. FACILITIES	COGEN	6,707,728,200			6,707,728,200	1.901	5.954	127,535,771

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-00	ECONPURCH	--	10,991,400	3.225	3.225	354,514	3.600	395,690	41,176
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		10,991,400	3.225	3.225	354,514	3.600	395,690	41,176
Feb-00	ECONPURCH	--	10,253,300	3.396	3.396	348,221	5.200	533,172	184,951
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		10,253,300	3.396	3.396	348,221	5.200	533,172	184,951
Mar-00	ECONPURCH	--	18,589,400	3.034	3.034	564,094	3.500	650,629	86,535
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		18,589,400	3.034	3.034	564,094	3.500	650,629	86,535
Apr-00	ECONPURCH	--	72,165,900	3.576	3.576	2,580,861	4.500	3,247,466	666,605
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		72,165,900	3.576	3.576	2,580,861	4.500	3,247,466	666,605
May-00	ECONPURCH	--	63,489,400	4.418	4.418	2,804,999	4.700	2,984,002	179,003
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		63,489,400	4.418	4.418	2,804,999	4.700	2,984,002	179,003
Jun-00	ECONPURCH	--	52,507,600	4.761	4.761	2,499,962	6.000	3,150,456	650,494
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		52,507,600	4.761	4.761	2,499,962	6.000	3,150,456	650,494

FLORIDA POWER CORPORATION
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-00	ECONPURCH	--	34,556,100	7.321	7.321	2,529,769	9.000	3,110,049	580,280
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		34,556,100	7.321	7.321	2,529,769	9.000	3,110,049	580,280
Aug-00	ECONPURCH	--	52,030,500	6.733	6.733	3,503,176	8.000	4,162,440	659,264
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	1
	TOTAL		52,030,500	6.733	6.733	3,503,176	8.000	4,162,440	659,265
Sep-00	ECONPURCH	--	44,873,700	5.027	5.027	2,255,591	5.500	2,468,054	212,463
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		44,873,700	5.027	5.027	2,255,591	5.500	2,468,054	212,463
Oct-00	ECONPURCH	--	60,828,500	4.080	4.080	2,481,654	4.500	2,737,283	255,629
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		60,828,500	4.080	4.080	2,481,654	4.500	2,737,283	255,629
Nov-00	ECONPURCH	--	44,470,100	3.092	3.092	1,375,164	3.400	1,511,983	136,819
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		44,470,100	3.092	3.092	1,375,164	3.400	1,511,983	136,819
Dec-00	ECONPURCH	--	25,244,200	2.228	2.228	562,470	3.500	883,547	321,077
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		25,244,200	2.228	2.228	562,470	3.500	883,547	321,077
Jan-00	ECONPURCH	--	490,000,100	4.461	4.461	21,860,475	5.272	25,834,770	3,974,295
THRU	OTHER	--	0	0.000	0.000	0	0.000	0	0
Dec-00	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		490,000,100	4.461	4.461	21,860,475	5.272	25,834,770	3,974,295

FLORIDA POWER CORPORATION
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2000

	DESCRIPTION		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Period Average	Prior Residential Bill *	Jan-00 vs. Prior
1	Base Rate Revenues	($)	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	49.05	0.00
2	Fuel Recovery Factor	(c/kwh)	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	2.050	1.893	
3	Fuel Cost Recovery Revenues	($)	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	20.53	18.96	1.57
4	Capacity Cost Recovery Revenues	($)	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	9.72	11.54	-1.82
5	Energy Conservation Cost Revenues	($)	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	3.21	-0.82
6	Gross Receipt Taxes	($)	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.09	2.12	-0.03
7	Total Revenues	($)	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	83.78	84.88	-1.10

* Actual Residential Billing for Dec-99

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			1998	1999	2000	2001	1999 vs. 1998	2000 vs. 1999	2001 vs. 2000
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		136,699,722	139,631,180	133,930,478		2.1%	-4.1%	0.0%
2	LIGHT OIL		36,471,069	33,919,060	43,728,159		-7.0%	28.9%	0.0%
3	COAL		266,537,992	249,844,129	253,479,749		-6.3%	1.5%	0.0%
4	GAS		91,480,392	133,960,072	147,488,328		46.4%	10.1%	0.0%
5	NUCLEAR		20,479,540	17,921,721	21,688,500		-12.5%	21.0%	0.0%
6	OTHER		0	0	0		0.0%	0.0%	0.0%
7	TOTAL	$	551,668,715	575,276,182	600,315,214		4.3%	4.4%	0.0%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		6,981,456	6,531,731	5,144,366		-6.4%	-21.2%	0.0%
9	LIGHT OIL		722,794	668,008	699,656		-7.6%	4.7%	0.0%
10	COAL		14,892,463	13,938,703	14,391,530		-6.4%	3.2%	0.0%
11	GAS		2,572,499	4,529,752	4,967,939		76.1%	9.7%	0.0%
12	NUCLEAR		5,862,675	5,728,402	6,348,026		-2.3%	10.8%	0.0%
13	OTHER		0	0	0		0.0%	0.0%	0.0%
14	TOTAL	MWH	31,031,877	31,396,596	31,551,516		1.2%	0.5%	0.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	10,868,893	10,288,196	8,142,910		-5.3%	-20.9%	0.0%
16	LIGHT OIL	BBL	1,688,743	1,544,945	1,623,269		-8.5%	5.1%	0.0%
17	COAL	TON	5,695,967	5,331,805	5,479,453		-6.4%	2.8%	0.0%
18	GAS	MCF	26,745,236	39,535,404	45,231,896		47.8%	14.4%	0.0%
19	NUCLEAR	MMBTU	60,338,861	58,873,598	65,722,728		-2.4%	11.6%	0.0%
20	OTHER	BBL	0	0	0		0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		70,386,994	66,490,224	52,114,622		-5.5%	-21.6%	0.0%
22	LIGHT OIL		9,844,014	8,996,190	9,414,959		-8.6%	4.7%	0.0%
23	COAL		141,896,299	134,085,571	137,715,270		-5.5%	2.7%	0.0%
24	GAS		28,141,474	40,738,436	45,231,896		44.8%	11.0%	0.0%
25	NUCLEAR		60,338,861	58,873,598	65,722,728		-2.4%	11.6%	0.0%
26	OTHER		0	0	0		0.0%	0.0%	0.0%
27	TOTAL	MMBTU	310,607,642	309,184,018	310,199,476		-0.5%	0.3%	0.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		22.50%	20.80%	16.31%		-7.6%	-21.6%	0.0%
29	LIGHT OIL		2.33%	2.13%	2.22%		-8.6%	4.7%	0.0%
30	COAL		47.99%	44.40%	45.61%		-7.5%	2.7%	0.0%
31	GAS		8.29%	14.43%	15.75%		73.6%	9.0%	0.0%
32	NUCLEAR		18.89%	18.25%	20.12%		-3.2%	10.4%	0.0%
33	OTHER		0.00%	0.00%	0.00%		0.0%	0.0%	0.0%
34	TOTAL	%	100.00%	100.00%	100.00%		0.0%	0.0%	0.0%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	12.58	13.57	16.45		7.9%	21.2%	0.0%
36	LIGHT OIL	$/BBL	21.60	21.95	26.94		1.7%	22.7%	0.0%
37	COAL	$/TON	46.79	46.86	46.26		0.1%	-1.3%	0.0%
38	GAS	$/MCF	3.42	3.39	3.26		-0.9%	-3.8%	0.0%
39	NUCLEAR	$/MMBTU	0.34	0.30	0.33		-10.3%	8.5%	0.0%
40	OTHER	$/BBL	0.00	0.00	0.00		0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								0.0%
41	HEAVY OIL		1.94	2.10	2.57		8.1%	22.4%	0.0%
42	LIGHT OIL		3.71	3.77	4.65		1.8%	23.2%	0.0%
43	COAL		1.88	1.86	1.84		-0.8%	-1.2%	0.0%
44	GAS		3.25	3.29	3.26		1.1%	-0.8%	0.0%
45	NUCLEAR		0.34	0.30	0.33		-10.3%	8.6%	0.0%
46	OTHER		0.00	0.00	0.00		0.0%	0.0%	0.0%
47	TOTAL	$/MMBTU	1.78	1.86	1.94		4.8%	4.0%	0.0%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,082	10,180	10,130		1.0%	-0.5%	0.0%
49	LIGHT OIL		13,619	13,467	13,457		-1.1%	-0.1%	0.0%
50	COAL		9,528	9,620	9,569		1.0%	-0.5%	0.0%
51	GAS		10,939	8,994	9,105		-17.8%	1.2%	0.0%
52	NUCLEAR		10,292	10,277	10,353		-0.1%	0.7%	0.0%
53	OTHER		0	0	0		0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	10,009	9,848	9,832		-1.6%	-0.2%	0.0%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		1.96	2.14	2.60		9.2%	21.8%	0.0%
56	LIGHT OIL		5.05	5.08	6.25		0.6%	23.1%	0.0%
57	COAL		1.79	1.79	1.76		0.2%	-1.7%	0.0%
58	GAS		3.56	2.96	2.97		-16.8%	0.4%	0.0%
59	NUCLEAR		0.35	0.31	0.34		-10.3%	9.3%	0.0%
60	OTHER		0.00	0.00	0.00		0.0%	0.0%	0.0%
61	TOTAL	C/KWH	1.78	1.83	1.90		3.1%	3.8%	0.0%

EXHIBIT NO. 22

DOCKET NO: 990001-EI

WITNESS: KARL WIELAND

PARTY: FLORIDA POWER CORPORATION

DESCRIPTION: COMPOSITE EXHIBIT: 1) FLORIDA POWER CORPORATION'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 10) AND 2) FLORIDA POWER CORPORATION'S RESPONSE TO LATE-FILED DEPOSITION EXHIBIT NO. 2

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 22
COMPANY/ WITNESS: PSC Staff
DATE: 11-22-99

10. Please provide a table which separately indicates on an annual basis the amount of economy energy that Florida Power purchased and sold through the EBN from 1990 to 1998.

Response: Data prior to 10/1/91 was not readily available from the Company's records. Also, the only available data was from A-schedules that covered the six-month periods October through March and April through September. We are providing annual amounts for the annual October through September period which shows annual trends in broker activity. The last period listed spans 15 months.

Purchases

Period	MWH	$
10/1/89 - 9/30/91	DATA NOT READILY AVAILABLE	
10/1/91 - 9/30/92	1,508,807	50,365,479
10/1/92 - 9/30/93	1,673,995	51,939,634
10/1/93 - 9/30/94	1,232,522	32,607,962
10/1/94 - 9/30/95	471,954	13,325,963
10/1/95 - 9/30/96	623,215	18,557,749
10/1/96 - 9/30/97	827,794	26,451,624
10/1/97 - 12/31/98	462,592	15,351,846

Note: Data source is Schedule A-9, Line 7, from the Company's semi-annual Fuel and Purchased Power True-up filings.

Sales

Period	MWH	$
10/1/89 - 9/30/91	DATA NOT READILY AVAILABLE	
10/1/91 - 9/30/92	455,537	6,633,708
10/1/92 - 9/30/93	374,469	5,776,812
10/1/93 - 9/30/94	467,892	7,917,159
10/1/94 - 9/30/95	756,956	13,332,030
10/1/95 - 9/30/96	546,377	9,440,986
10/1/96 - 9/30/97	127,173	2,323,046
10/1/97 - 12/31/98	234,669	3,687,976

Note: Data source is Schedule A-6, Line 14, from the Company's semi-annual Fuel and Purchased Power True-up filings.

FLORIDA POWER CORPORATION

COMPARISON OF 2000 JURISDICTIONAL TRANSMISSION REVENUES
PRODUCTION ENERGY ALLOCATION FACTOR VS. TRANSMISSION ALLOCATION FACTOR

	Production Energy Allocation	Transmission Allocation
Energy Sales - Mwh (Sch E1 Line 15)	1,445,001	1,445,001
Estimated Transmission Rate ($/Mwh) [3]	2.69	2.69
Estimated Transmission Revenues	$3,887,053	$3,887,053
Retail Separation Factor	97.2% [1]	69.4% [2]
Retail Allocation	$3,778,215	$2,697,615
Difference		$1,080,601

(1) Source: Fuel and Purchased Power Cost Recovery Clause, Schedule E1 line 26 / line 24.
(2) Source: Projected 1999 Jurisdictional Separation Study.
(3) Based on actual results - January through September 1999.

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. 23 (TAD-1)
Schedule 1
Page 1 of 3

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
April 1998 - December 1998

1. Estimated over/(under) - recovery for the period April 1998 - December 1998 (Schedule E1-A approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	(3,287,553)
2. Actual over/(under)-recovery for the period April 1998 - December 1998 (SEP 1998 & DEC 1998 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7 and 8)	(5,737,753)
3. Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	($2,450,200)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 23
COMPANY/ WITNESS: Davis
DATE: 11-22-99

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. _____ (TAD-1)
Schedule 1
Page 2 of 3

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
April 1998 - September 1998

1. Estimated over/(under) - recovery for the period April 1998 - September 1998 (Schedule E1-A approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	(3,743,611)
2. Actual over/(under)-recovery for the period April 1998 - September 1998 (SEP 1998 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7 and 8)	(6,437,743)
3. Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	($2,694,132)

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. _____ (TAD-1)
Schedule 1
Page 3 of 3

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
October 1998 - December 1998

1. Estimated over/(under) - recovery for the period October 1998 - December 1998 (Schedule E1-A approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	456,058
2. Actual over/(under)-recovery for the period October 1998 - December 1998 (DEC 1998 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7 and 8)	699,990
3. Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	$243,932

Florida Public Service Commission
Docket No. 990001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. ____ (TAD -1)
SCHEDULE CCA-1
Page 1 of 3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
OCTOBER 1997 - DECEMBER 1998

1.	Estimated over/(under)-recovery for the period OCTOBER 1997 - DECEMBER 1998 (Schedule CCE-1a approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	(3,704,945)
2.	Actual over/(under)-recovery for the period OCTOBER 1997 - DECEMBER 1998 (Schedule CCA-2 Pages 1 & 2 Line 11+12 in the Total column)	(3,623,821)
3.	Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	81,124

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
OCTOBER 1997 - SEPTEMBER 1998

1.	Estimated over/(under)-recovery for the period OCTOBER 1997 - SEPTEMBER 1998 (Schedule CCE-1a approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	(2,467,419)
2.	Actual over/(under)-recovery for the period OCTOBER 1997 - SEPTEMBER 1998 (Schedule CCA-2 Page 1 of 2 Line 11+12 in the Total column)	(2,563,148)
3.	Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	(95,729)

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
OCTOBER 1998 - DECEMBER 1998

1.	Estimated over/(under)-recovery for the period OCTOBER 1998 - DECEMBER 1998 (Schedule CCE-1a approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998)	(1,237,526)
2.	Actual over/(under)-recovery for the period OCTOBER 1998 - DECEMBER 1998 (Schedule CCA-2 Page 2 of 2 Line 11+12 in the Total column)	(1,060,673)
3.	Amount to be refunded/(recovered) in the JANUARY 2000 - DECEMBER 2000 projection period (Line 2 - Line 1)	176,853

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD OCTOBER 1997 - SEPTEMBER 1998

		ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL TOTAL
1.	IIC Payments / (Receipts) ($)	(33,415)	(442,075)	513,640	657,730	512,188	199,724	152,743	300,330	285,148	608,091	519,945	665,067	3,939,116
2.	Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3.	Total Capacity Payments/(Receipts) (Line 1 + 2) ($)	28,787	(379,873)	575,842	719,932	574,390	261,926	214,945	362,532	347,350	670,293	582,147	727,269	4,685,540
4.	Jurisdictional %	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890	0.9631890
5.	Jurisdictional Capacity Payments / (Receipts) (Line 3 x 4) ($)	27,727	(365,889)	554,644	693,430	553,246	252,284	207,033	349,186	334,564	645,619	560,718	700,498	4,513,060
6.	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(1,652,000)
7.	Total Jurisdictional Recovery Amount (Line 5 - 6) ($)	165,394	(228,222)	692,311	831,097	690,912	389,950	344,700	486,853	472,231	783,286	698,384	838,164	6,165,060
8.	Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	302,620	273,048	319,053	300,844	267,335	293,673	269,646	368,891	434,861	455,294	442,168	378,864	4,106,297
9.	True-Up Provision ($)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,664)	(43,663)	(523,967)
10.	Jurisdictional Capacity Cost Recovery Revenue (Line 8 + 9) ($)	258,956	229,384	275,389	257,180	223,671	250,009	225,982	325,227	391,197	411,630	398,504	335,201	3,582,330
11.	Over/(Under) Recovery (Line 10 - 7) ($)	93,562	457,606	(416,922)	(573,917)	(467,241)	(139,941)	(118,718)	(161,626)	(81,034)	(371,655)	(299,880)	(502,963)	(2,582,729)
12.	Interest Provision ($)	4,715	6,247	6,703	4,557	2,297	1,119	728	285	(71)	(922)	(2,268)	(3,809)	19,581
13.	Beginning Balance True-Up & Interest Provision ($)	954,488	1,096,429	1,603,946	1,237,391	711,695	290,415	195,257	120,931	3,254	(34,187)	(363,100)	(621,584)	954,488
14.	True-Up Collected/(Refunded) ($)	43,664	43,664	43,664	43,664	43,664	43,664	43,664	43,664	43,664	43,664	43,664	43,663	523,967
15.	End Of Period Total Net True-Up (Lines 11 + 12 + 13 + 14) ($)	1,096,429	1,603,946	1,237,391	711,695	290,415	195,257	120,931	3,254	(34,187)	(363,100)	(621,584)	(1,084,693)	

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD OCTOBER 1998 - DECEMBER 1998

		ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL TOTAL
1.	IIC Payments / (Receipts) ($)	184,067	172,724	272,498	629,289
2.	Capacity Payments to Solutia ($)	62,202	62,202	62,202	186,606
3.	Total Capacity Payments/(Receipts) (Line 1 + 2) ($)	246,269	234,926	334,700	815,895
4.	Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271
5.	Jurisdictional Capacity Payments / (Receipts) (Line 3 x 4) ($)	237,607	226,663	322,928	787,198
6.	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(413,001)
7.	Total Jurisdictional Recovery Amount (Line 5 - 6) ($)	375,274	364,330	460,595	1,200,199
8.	Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	321,903	265,662	478,691	1,066,256
9.	True-Up Provision ($)	(303,774)	(303,774)	(303,775)	(911,323)
10.	Jurisdictional Capacity Cost Recovery Revenue (Line 8 + 9) ($)	18,129	(38,112)	174,916	154,933
11.	Over/(Under) Recovery (Line 10 - 7) ($)	(357,145)	(402,442)	(285,679)	(1,045,266)
12.	Interest Provision ($)	(4,779)	(5,265)	(5,363)	(15,407)
13.	Beginning Balance True-Up & Interest Provision ($)	(1,084,693)	(1,142,843)	(1,246,776)	(1,084,693)
14.	True-Up Collected/(Refunded) ($)	303,774	303,774	303,775	911,323
15.	End Of Period Total Net True-Up (Lines 11 + 12 + 13 + 14) ($)	(1,142,843)	(1,246,776)	(1,234,043)	

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD OCTOBER 1996 - SEPTEMBER 1997

	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	TOTAL
1. Beginning True-Up Amount ($)	954,488	1,096,429	1,603,946	1,237,391	711,695	290,415	195,257	120,931	3,254	(34,187)	(363,100)	(621,584)	
2. Ending True-Up Amount Before Interest ($)	1,091,714	1,597,699	1,230,688	707,138	288,118	194,138	120,203	2,969	(34,116)	(362,178)	(619,316)	(1,080,884)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	2,046,202	2,694,128	2,834,634	1,944,529	999,813	484,553	315,460	123,900	(30,862)	(396,365)	(982,416)	(1,702,468)	
4. Average True-Up Amount ($)	1,023,101	1,347,064	1,417,317	972,265	499,907	242,277	157,730	61,950	(15,431)	(198,183)	(491,208)	(851,234)	
5. Interest Rate - First Day of Reporting Business Month	0.055300	0.055300	0.056000	0.057500	0.055000	0.055300	0.055500	0.055300	0.055000	0.056000	0.055600	0.055200	
6. Interest Rate - First Day of Subsequent Business Month	0.055300	0.056000	0.057500	0.055000	0.055300	0.055500	0.055300	0.055000	0.056000	0.055600	0.055200	0.052200	
7. Total Interest Rate (Lines 5 + 6)	0.110600	0.111300	0.113500	0.112500	0.110300	0.110800	0.110800	0.110300	0.111000	0.111600	0.110800	0.107400	
8. Average Interest Rate	0.055300	0.055650	0.056750	0.056250	0.055150	0.055400	0.055400	0.055150	0.055500	0.055800	0.055400	0.053700	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.004608	0.004638	0.004729	0.004688	0.004596	0.004617	0.004617	0.004596	0.004625	0.004650	0.004617	0.004475	
10. Interest Provision For the Month (Lines 4 X 9) ($)	4,715	6,247	6,703	4,557	2,297	1,119	728	285	(71)	(922)	(2,268)	(3,809)	19,581

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD OCTOBER 1998 - December 1998

		ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1.	Beginning True-Up Amount ($)	(1,084,693)	(1,142,843)	(1,246,776)	
2.	Ending True-Up Amount Before Interest ($)	(1,138,064)	(1,241,511)	(1,228,680)	
3.	Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(2,222,757)	(2,384,354)	(2,475,456)	
4.	Average True-Up Amount ($)	(1,111,379)	(1,192,177)	(1,237,728)	
5.	Interest Rate - First Day of Reporting Business Month	0.052200	0.051000	0.055000	
6.	Interest Rate - First Day of Subsequent Business Month	0.051000	0.055000	0.049000	
7.	Total Interest Rate (Lines 5 + 6)	0.103200	0.106000	0.104000	
8.	Average Interest Rate	0.051600	0.053000	0.052000	
9.	Monthly Average Interest Rate (1/12 Of Line 8)	0.004300	0.004417	0.004333	
10.	Interest Provision For the Month (Lines 4 X 9) ($)	(4,779)	(5,265)	(5,363)	(15,407)

SCHEDULE E-1
Revised 11/12/99

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	195,007,137	12,169,190,000	1.6025
2	Nuclear Fuel Disposal Costs		E-2	0	0	#N/A
3	Coal Car Investment			0	0	#N/A
4	Other Generation			1,927,026	102,720,000	1.8760
5	**Total Cost of Generated Power**	(Line 1 - 4)		196,934,163	12,271,910,000	1.6048
6	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
7	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
8	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	31,414,000	1,072,290,000	2.9296
9	Energy Cost of Schedule E Economy Purch.		E-9	0	0	#N/A
10	Capacity Cost of Schedule E Economy Purchases		E-2	0	0	#N/A
11	Energy Payments to Qualifying Facilities		E-8	208,732	9,130,000	2.2862
12	**Total Cost of Purchased Power**	(Line 6 - 11)		31,622,732	1,081,420,000	2.9242
13	**Total Available KWH**	(Line 5 + 12)			13,353,330,000	
14	Fuel Cost of Economy Sales		E-6	(4,355,000)	(189,030,000)	2.3039
15	Gain on Economy Sales		E-6	(440,000)		#N/A
16	Fuel Cost of Unit Power Sales		E-6	(13,810,000)	(729,170,000)	1.8939
17	Fuel Cost of Other Power Sales			(24,866,000)	(1,393,865,000)	1.7840
18	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -17)		(43,471,000)	(2,312,065,000)	1.8802
19	Net Inadvertant Interchange			0	0	#N/A
20	**Total Fuel & Net Power Trans.**	(Line 5+12+18+19)		185,085,895	11,041,265,000	1.6763
21	Net Unbilled Sales *			0	0	#N/A
22	Company Use *			377,218	22,503,000	1.6763
23	T & D Losses *			1,080,236	644,417,000	1.6763
24	**System KWH Sales**			185,085,895	10,374,345,000	1.7841
25	Wholesale KWH Sales			6,433,893	360,624,000	1.7841
26	Jurisdictional KWH Sales			178,652,002	10,013,721,000	1.7841
26a	Jurisdictional Line Loss Multiplier			1.0014		1.0014
27	Jurisdictional KWH Sales Adjusted for Line Losses			178,902,115	10,013,721,000	1.7866
28	**True-Up ****			13,752,459	10,013,721,000	0.1373
29	**Total Jurisdictional Fuel Cost**			192,654,574	10,013,721,000	1.9239
30	Revenue Tax Factor					1.01597
31	Fuel Factor Adjusted For Revenue Taxes					1.9546
32	GPIF Reward/(Penalty) **			(36,679)	10,013,721,000	(0.0004)
33	Fuel Factor Adjusted for Spec. Cont. Rec. & GPIF					1.9542
34	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**1.954**

*For informational purposes only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 24
COMPANY/ WITNESS: Davis
DATE: 11-22-00

SCHEDULE E-1A

CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 1999 (Sch. E-1B, page 2, line 8)	($11,302,259)
2.	Final over/(under)-recovery APRIL - SEPTEMBER 1998 (EXHIBIT No.____(TAD-1), filed April 1, 1999	($2,694,132)
3.	Final over/(under)-recovery OCTOBER - DECEMBER 1998 (EXHIBIT No.____(TAD-1), filed April 1, 1999	243,932
4.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2000 - DECEMBER 2000 (Schedule E1, Line 28)	($13,752,459)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000	10,013,721,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1373

SCHEDULE E-1B
Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

				JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		14,351,953.22	9,860,077.35	13,191,125.11	14,863,512.47	17,803,592.11	19,370,034.96	$89,440,295.22
	2	Fuel Cost of Power Sold		(3,008,087.58)	(1,275,456.79)	(4,581,153.46)	(6,164,111.68)	(5,801,721.75)	(6,169,985.70)	($27,000,516.96)
	3	Fuel Cost of Purchased Power		1,281,132.92	1,888,655.37	809,394.67	4,183,039.81	772,463.85	2,969,131.87	11,903,818.49
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities		144,098.58	325,163.30	353,966.39	471,354.71	258,933.13	220,062.00	1,773,578.11
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation		164,962.27	128,390.94	153,585.56	143,239.28	143,105.29	136,738.10	870,021.44
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$12,934,059.41	$10,926,830.17	$9,926,918.27	$13,497,034.59	$13,176,372.63	$16,525,981.23	$76,987,196.30
B	1	Jurisdictional KWH Sales		739,104,445	602,521,261	645,839,727	711,513,543	796,267,435	910,695,185	4,405,941,596
	2	Non-Jurisdictional KWH Sales		24,226,819	22,364,388	23,203,899	24,870,728	27,675,927	30,778,442	153,120,203
	3	TOTAL SALES (Lines B1 + B2)		763,331,264	624,885,649	669,043,626	736,384,271	823,943,362	941,473,627	4,559,061,799
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.8262%	96.4210%	96.5318%	96.6226%	96.6410%	96.7308%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$12,059,017.95	$9,860,883.55	$10,521,228.60	$11,633,665.19	$13,027,358.60	$14,931,967.19	$72,034,121.08
	1a	Special Contract Recovery Cost		(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(60,868.98)
	2	True-Up Provision		(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(2,192,287.50)
	2a	Incentive Provision		(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(30,823.50)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$11,678,354.62	$9,480,220.22	$10,140,565.27	$11,253,001.86	$12,646,695.27	$14,551,303.86	$69,750,141.10
	4	Fuel & Net Power Transactions (Line A6)		$12,934,059.41	$10,926,830.17	$9,926,918.27	$13,497,034.59	$13,176,372.63	$16,525,981.23	$76,987,196.30
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		12,541,091.21	10,550,508.98	9,596,048.58	13,059,443.40	12,751,605.56	16,008,093.85	$74,506,791.58
	6	Over/(Under) Recovery (Line C3-C5)		(862,736.59)	(1,070,288.76)	544,516.69	(1,806,441.54)	(104,910.29)	(1,456,789.99)	($4,756,650.48)
	7	Interest Provision	(2)	(28,659.66)	(31,045.81)	(30,979.84)	(32,015.39)	(34,422.44)	(37,168.55)	($194,291.69)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 1999 - DECEMBER 1999**								($4,950,942.17)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

				JULY ACTUAL	AUGUST ACTUAL	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		22,219,817.08	22,978,684.23	17,129,407.00	16,856,077.00	14,847,061.00	13,824,090.00	$197,295,431.53
	2	Fuel Cost of Power Sold		(10,287,872.88)	(15,896,257.40)	(3,862,800.00)	(5,763,800.00)	(4,192,800.00)	(2,359,400.00)	($69,363,447.24)
	3	Fuel Cost of Purchased Power		7,031,703.54	12,568,967.75	891,000.00	251,000.00	110,000.00	1,289,000.00	$34,045,489.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		873,664.00	966,622.00	19,378.00	2,422.00	0.00	0.00	$3,635,664.11
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		136,738.00	129,653.98	168,375.00	173,971.00	168,375.00	173,971.00	$1,821,105.42
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$19,974,049.74	$20,747,670.56	$14,345,360.00	$11,519,670.00	$10,932,636.00	$12,927,661.00	$167,434,243.60
B	1	Jurisdictional KWH Sales		1,020,841,104	1,058,379,070	876,848,000	702,438,000	659,165,000	791,003,000	9,514,615,770
	2	Non-Jurisdictional KWH Sales		34,945,824	38,187,471	31,340,000	27,518,000	26,107,000	29,043,000	340,261,498
	3	TOTAL SALES (Lines B1 + B2)		1,055,786,928	1,096,566,541	908,188,000	729,956,000	685,272,000	820,046,000	9,854,877,268
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.6901%	96.5175%	96.5492%	96.2302%	96.1903%	96.4584%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$16,742,454.02	$17,367,278.57	$14,344,356.43	$11,491,183.24	$10,783,280.24	$12,940,018.08	$155,702,691.66
	1a	Special Contract Recovery Cost		(10,144.83)	(10,144.83)	(10,144.84)	(10,144.84)	(10,144.84)	(10,144.84)	($121,738.00)
	2	True-Up Provision		(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	($4,384,575.00)
	2a	Incentive Provision		(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	($61,647.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$16,361,790.69	$16,986,615.24	$13,963,693.09	$11,110,519.90	$10,402,616.90	$12,559,354.74	$151,134,731.66
	4	Fuel & Net Power Transactions (Line A6)		$19,974,049.74	$20,747,670.56	$14,345,360.00	$11,519,670.00	$10,932,636.00	$12,927,661.00	$167,434,243.60
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		19,339,966.77	20,053,168.12	13,869,720.78	11,100,921.04	10,530,857.96	12,487,272.70	$161,888,698.95
	6	Over/(Under) Recovery (Line C3-C5)		(2,978,176.08)	(3,066,552.88)	93,972.31	9,598.86	(128,241.06)	72,082.04	($10,753,967.29)
	7	Interest Provision	(2)	(46,095.38)	(59,063.82)	(64,187.27)	(62,654.63)	(61,597.76)	(60,400.65)	($548,291.20)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 1999 - DECEMBER 1999**								($11,302,258.49)

Note 1: Estimated Revenues based on the Jan through Dec Fuel Factor excluding revenue taxes of 1.6359 ¢/KWH
Note 2: Interest Calculated for September through December at August's rate of 0.4342

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ACTUAL	EST.	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	197,295,432	190,141,031	7,154,401	3.76	12,636,967,000	12,440,570,000	196,397,000	1.58	1.5613	1.5284	0.0329	2.15
2	Nuclear Fuel Disposal Costs	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,821,105	1,981,161	(160,056)	(8.08)	113,441,000	123,900,000	(10,459,000)	(8.44)	1.6053	1.599	0.0063	0.39
5	TOTAL COST OF GENERATED POWER	199,116,537	192,122,192	6,994,345	3.64	12,750,408,000	12,564,470,000	185,938,000	1.48	1.5616	1.5291	0.0325	2.13
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	7,144,399	0	7,144,399	#N/A	168,529,072	0	168,529,072	#N/A	4.2393	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	26,901,091	10,269,000	16,632,091	100.00	865,855,793	531,400,000	334,455,793	62.94	3.1069	1.9324	1.1745	60.78
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	3,635,664	194,260	3,441,404	1,771.55	109,740,265	8,970,000	100,770,265	1,123.41	3.313	2.1657	1.1473	52.98
12	TOTAL COST OF PURCHASED POWER	37,681,154	10,463,260	27,217,894	260.13	1,144,125,130	540,370,000	603,755,130	111.73	3.2934	1.9363	1.3571	70.09
13	Total Available KWH (Lines 4 + Line 12)	236,797,691	202,585,452	34,212,239	16.89	13,894,533,130	13,104,840,000	789,693,130	6.03				
14	Fuel Cost of Economy Sales (A6)	(1,643,879)	(1,337,000)	(306,879)	(22.95)	(75,326,814)	(50,260,000)	(25,066,814)	(49.87)	(2.1823)	(2.6602)	0.4779	17.96
15	Gain on Economy Sales (A6)	(680,827)	(141,600)	(539,227)	(380.81)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(14,326,927)	(12,794,000)	(1,532,927)	(11.98)	(794,513,045)	(685,670,000)	(108,843,045)	(15.87)	(1.8032)	(1.8659)	0.0627	3.36
17	Fuel Cost of Other Power Sales (A6)	(52,711,815)	(29,490,000)	(23,221,815)	(78.74)	(2,533,054,867)	(1,716,879,000)	(816,175,867)	(47.54)	(2.0810)	(1.7177)	(0.3633)	(21.15)
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(69,363,448)	(43,762,600)	(25,600,848)	(58.50)	(3,402,894,726)	(2,452,809,000)	(950,085,726)	(38.73)	(2.0384)	(1.7842)	(0.2542)	(14.25)
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	167,434,243	158,822,852	8,611,391	5.42	10,491,638,404	10,652,031,000	(160,392,596)	(1.51)	1.5959	1.491	0.1049	7.04
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	337,043	305,402	31,641	10.36	21,119,298	20,483,000	636,298	3.11	1.5959	1.491	0.1049	7.04
23	T & D Losses *	9,825,028	9,229,022	596,006	6.46	615,641,838	618,982,000	(3,340,162)	(0.54)	1.5959	1.491	0.1049	7.04
24	TERRITORIAL (SYSTEM) SALES	167,434,243	158,822,852	8,611,391	5.42	9,854,877,268	10,012,566,000	(157,688,732)	(1.57)	1.699	1.5862	0.1128	7.11
25	Wholesale Sales	5,771,871	5,576,080	195,791	3.51	340,261,498	351,537,000	(11,275,502)	(3.21)	1.6963	1.5862	0.1101	6.94
26	Jurisdictional Sales	161,662,372	153,246,772	8,415,600	5.49	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.6991	1.5862	0.1129	7.12
26a	Jurisdictional Loss Multiplier	1.0014	1.0014										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0014)	161,888,699	153,461,317	8,427,382	5.49	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.7015	1.5885	0.1130	7.11
28	TRUE-UP **	4,384,575	4,384,575	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0461	0.0454	0.0007	1.54
29	TOTAL JURISDICTIONAL FUEL COST	166,273,274	157,845,892	8,427,382	5.34	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.7476	1.6339	0.1137	6.96
30	Revenue Tax Factor									1.01609	1.01609		
31	Fuel Factor Adjusted for Revenue Taxes									1.7757	1.6602	0.1155	6.96
32	GPIF Reward / (Penalty) **	62,632	62,632	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0007	0.0006	0.0001	16.67
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									1.7764	1.6608	0.1156	6.96
33a	Special Contract Recovery Cost (Incl. Revenue Taxes) **	123,682	123,682	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0013	0.0013	0.0000	0.00
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									1.778	1.662	0.116	6.98

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 8 months actual and 4 month estimates. Amounts Included in the Estimated Original Column represent amounts projected in previous fuel adjustment period.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	(36,679)
	B. True-Up (Over)/Under Recovered	$	13,752,459
2.	TOTAL SALES (KWH)		10,013,721,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		(0.0004)
	B. True-Up Factor		0.1373

SCHEDULE E-1D
Revised 11/12/99

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		NET ENERGY FOR LOAD %
	On-Peak	34.68
	Off-Peak	65.32
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	1.7841	2.2290	1.5479
Jurisdictional Loss Factor	1.0014	1.0014	1.0014
Jurisdictional Fuel Factor	1.7866	2.2321	1.5501
GPIF	(0.0004)	(0.0004)	(0.0004)
True-Up	0.1373	0.1373	0.1373
TOTAL	1.9235	2.369	1.687
Revenue Tax Factor	1.01597	1.01597	1.01597
Recovery Factor	1.9542	2.4068	1.7139
Recovery Factor Rounded to the Nearest .001 ¢/KWH	1.954	2.407	1.714

HOURS:	ON-PEAK	24.93%
	OFF-PEAK	75.07%
		100.00%

SCHEDULE E-1E
Revised 11/12/99

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, OSIV, SBS (1)	1.954	1.01228	1.978
B	LP, SBS (2)	1.954	0.98106	1.917
C	PX, RTP, SBS (3)	1.954	0.96230	1.880
D	OSI, OSII	1.954	1.01228	1.910 *

		TOU
A	On-Peak	2.436
	Off-Peak	1.735
B	On-Peak	2.361
	Off-Peak	1.681
C	On-Peak	2.316
	Off-Peak	1.649
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	2.407 ¢ / KWH	x	0.2493	=	0.600 ¢ / KWH
	Off-Peak	1.714 ¢ / KWH	x	0.7507	=	1.287 ¢ / KWH
						1.887 ¢ / KWH
			Line Loss Multiplier		x	1.01228
						1.910 ¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

SCHEDULE E-2
Revised 11/12/99

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	14,991,952	11,977,253	11,448,315	14,742,838	16,730,497	19,610,417	21,027,459	21,823,642	17,513,543	13,563,278	15,268,803	16,309,140	195,007,137
1a	Other Generation	163,212	152,706	163,212	157,959	163,212	157,959	163,212	163,212	157,959	163,212	157,959	163,212	1,927,026
2	Fuel Cost of Power Sold	(2,287,000)	(1,902,000)	(2,738,000)	(3,767,000)	(3,591,000)	(4,071,000)	(5,536,000)	(5,994,000)	(3,690,000)	(2,669,000)	(3,777,000)	(3,449,000)	(43,471,000)
3	Fuel Cost of Purchased Power	1,675,000	1,229,000	4,235,000	1,130,000	1,146,000	3,456,000	6,388,000	6,078,000	2,381,000	1,494,000	582,000	1,620,000	31,414,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	4,319	664	3,654	6,042	13,247	18,824	67,396	78,551	12,317	3,718	0	0	208,732
4	Energy Cost of Economy Purchases													0
5	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	14,547,483	11,457,623	13,112,181	12,269,839	14,461,956	19,172,200	22,110,067	22,149,405	16,374,819	12,555,208	12,231,762	14,643,352	185,085,895
6	System KWH Sold	857,362,000	708,547,000	753,891,000	750,400,000	880,287,000	1,025,331,000	1,066,097,000	1,071,696,000	936,129,000	756,228,000	715,783,000	852,594,000	10,374,345,000
6a	Jurisdictional % of Total Sales	96.4705	96.1668	96.4674	96.4280	96.5013	96.8142	96.5658	96.6864	96.6523	96.2556	96.3081	96.7044	96.5239
7	Cost per KWH Sold (¢/KWH)	1.6968	1.6171	1.7393	1.6351	1.6429	1.8699	2.0739	2.0668	1.7492	1.6602	1.7089	1.7175	1.7841
7a	Jurisdictional Loss Multiplier	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014
7b	Jurisdictional Cost (¢/KWH)	1.6992	1.6194	1.7417	1.6374	1.6452	1.8725	2.0768	2.0697	1.7516	1.6625	1.7113	1.7199	1.7866
8	GPIF (¢ / KWH) *	(0.0004)	(0.0004)	(0.0004)	(0.0004)	(0.0004)	(0.0003)	(0.0003)	(0.0003)	(0.0003)	(0.0004)	(0.0004)	(0.0004)	(0.0004)
9	True-Up (¢/KWH) *	0.1386	0.1682	0.1576	0.1584	0.1349	0.1155	0.1113	0.1106	0.1267	0.1574	0.1662	0.1390	0.1373
10	TOTAL	1.8374	1.7872	1.8989	1.7954	1.7797	1.9877	2.1878	2.1800	1.8780	1.8195	1.8771	1.8585	1.9235
11	Revenue Tax Factor	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597
12	Recovery Factor Adjusted for Taxes	1.8667	1.8157	1.9292	1.8241	1.8081	2.0194	2.2227	2.2148	1.9080	1.8486	1.9071	1.8882	1.9542
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	1.867	1.816	1.929	1.824	1.808	2.019	2.223	2.215	1.908	1.849	1.907	1.888	1.954

* CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
2	LIGHTER OIL	26,611	26,925	22,018	26,884	27,388	27,506	28,096	28,162	28,221	23,593	28,313	28,352	322,069
3	COAL excluding Scherer	13,559,495	11,275,604	9,115,874	12,587,322	14,699,319	17,133,249	17,858,376	18,573,039	15,032,032	11,431,118	13,273,673	14,421,084	168,960,185
3a	COAL at Scherer	1,374,365	649,838	2,292,463	2,111,428	1,981,436	2,148,972	2,252,376	2,278,698	2,029,017	2,094,343	1,949,136	1,841,512	23,003,584
4	GAS	2,840	6,224	8,543	1,123	4,999	283,882	858,563	911,729	405,901	0	0	58	2,483,862
4a	GAS (B.L.)	18,134	17,681	8,030	16,081	16,081	16,081	17,221	17,221	16,081	14,224	17,681	18,134	192,650
6	OTHER - C.T.	10,507	981	1,387	0	1,274	727	12,827	14,793	2,291	0	0	0	44,787
6a	OTHER GENERATION	163,212	152,706	163,212	157,959	163,212	157,959	163,212	163,212	157,959	163,212	157,959	163,212	1,927,026
7	TOTAL ($)	15,155,164	12,129,959	11,611,527	14,900,797	16,893,709	19,768,376	21,190,671	21,986,854	17,671,502	13,726,490	15,426,762	16,472,352	196,934,163
	SYSTEM NET GEN. (MWH)													
8	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
9	LIGHTER OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
10	COAL	970,730	780,220	714,420	939,900	1,052,990	1,219,570	1,259,290	1,305,120	1,061,890	848,590	952,150	1,008,340	12,113,210
11	GAS	70	150	200	30	130	6,500	18,750	20,140	9,050	0	0	0	55,020
13	OTHER - C.T.	230	20	30	0	30	20	270	310	50	0	0	0	960
13a	OTHER GENERATION	8,700	8,140	8,700	8,420	8,700	8,420	8,700	8,700	8,420	8,700	8,420	8,700	102,720
14	TOTAL (MWH)	979,730	788,530	723,350	948,350	1,061,850	1,234,510	1,287,010	1,334,270	1,079,410	857,290	960,570	1,017,040	12,271,910
	UNITS OF FUEL BURNED													
15	HEAVY OIL (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
16	LIGHTER OIL (BBL)	1,344	1,342	1,082	1,321	1,338	1,338	1,335	1,335	1,334	1,114	1,334	1,334	15,551
17	COAL excl. Scherer (TON)	410,805	344,116	264,523	372,935	427,761	489,105	504,733	520,479	419,704	318,892	369,810	400,934	4,843,797
18	GAS-all (MCF)	7,222	8,442	5,853	6,680	8,185	116,468	317,543	336,820	163,845	5,523	6,244	6,264	989,089
20	OTHER - C.T. (BBL)	539	50	71	0	65	37	652	746	115	0	0	0	2,275
	BTU'S BURNED (MMBTU)													
21	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
22	LIGHTER OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
23	COAL + GAS B.L. + OIL B.L.	10,032,973	8,031,773	7,409,674	9,653,041	10,942,597	12,569,224	13,036,498	13,466,844	11,017,973	8,792,229	9,825,798	10,481,757	125,260,381
24	GAS-Generation	1,007	2,264	3,108	449	1,999	113,531	320,638	340,493	162,329	0	0	21	945,839
26	OTHER - C.T.	3,141	293	414	0	380	217	3,802	4,356	674	0	0	0	13,277
27	TOTAL (MMBTU)	10,037,121	8,034,330	7,413,196	9,653,490	10,944,976	12,682,972	13,360,938	13,811,693	11,180,976	8,792,229	9,825,798	10,481,778	126,219,497

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
28	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	LIGHTER OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	COAL	99.08	98.95	98.77	99.11	99.17	98.79	97.84	97.82	98.38	98.99	99.12	99.14	98.70
31	GAS-Generation	0.01	0.02	0.03	0.00	0.01	0.53	1.46	1.51	0.84	0.00	0.00	0.00	0.45
33	OTHER - C.T.	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.01
33a	OTHER GENERATION	0.89	1.03	1.20	0.89	0.82	0.68	0.68	0.65	0.78	1.01	0.88	0.86	0.84
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
35	HEAVY OIL ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
36	LIGHTER OIL ($/BBL)	19.80	20.06	20.35	20.35	20.47	20.56	21.05	21.10	21.16	21.18	21.22	21.25	20.71
37	COAL ($/TON)	33.01	32.77	34.46	33.75	34.36	35.03	35.38	35.68	35.82	35.85	35.89	35.97	34.88
38	GAS + B.L. ($/MCF)	2.90	2.83	2.83	2.58	2.58	2.58	2.76	2.76	2.58	2.58	2.83	2.90	2.71
40	OTHER - C.T.	19.49	19.62	19.54	#N/A	19.60	19.65	19.67	19.83	19.92	#N/A	#N/A	#N/A	19.69
	FUEL COST $ / MMBTU													
41	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.49	1.49	1.54	1.52	1.53	1.54	1.54	1.55	1.55	1.54	1.55	1.55	1.53
44	GAS-Generation	2.82	2.75	2.75	2.50	2.50	2.50	2.68	2.68	2.50	#N/A	#N/A	2.76	2.63
46	OTHER - C.T.	3.35	3.35	3.35	#N/A	3.35	3.35	3.37	3.40	3.40	#N/A	#N/A	#N/A	3.37
47	TOTAL ($/MMBTU)	1.51	1.51	1.57	1.54	1.54	1.56	1.59	1.59	1.58	1.56	1.57	1.57	1.56
	BTU BURNED BTU / KWH													
48	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,335	10,294	10,372	10,270	10,392	10,306	10,352	10,318	10,376	10,361	10,320	10,395	10,341
51	GAS-Generation	14,386	15,093	15,540	14,967	15,377	17,466	17,101	16,906	17,937	#N/A	#N/A	#N/A	17,191
53	OTHER - C.T.	13,657	14,650	13,800	#N/A	12,667	10,850	14,081	14,052	13,480	#N/A	#N/A	#N/A	13,830
54	TOTAL (BTU/KWH)	10,245	10,189	10,248	10,179	10,307	10,274	10,381	10,351	10,358	10,256	10,229	10,306	10,285
	FUEL COST CENTS / KWH													
55	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.54	1.53	1.60	1.57	1.59	1.58	1.60	1.60	1.61	1.60	1.60	1.62	1.59
58	GAS-Generation	4.06	4.15	4.27	3.74	3.85	4.37	4.58	4.53	4.49	#N/A	#N/A	#N/A	4.51
60	OTHER - C.T.	4.57	4.91	4.62	#N/A	4.25	3.64	4.75	4.77	4.58	#N/A	#N/A	#N/A	4.67
60a	OTHER GENERATION	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
61	TOTAL (¢/KWH)	1.55	1.54	1.61	1.57	1.59	1.60	1.65	1.65	1.64	1.60	1.61	1.62	1.60

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	20	0.1	100.0	0.1	15,700	Gas - G	305	1,030	314	886	4.43	2.90
2	1							Oil - G						
3	Crist 2	24.0	20	0.1	100.0	0.1	12,400	Gas - G	241	1,030	248	699	3.50	2.90
4	2							Oil - G						
5	Crist 3	35.0	30	0.1	100.0	0.1	14,833	Gas - G	432	1,030	445	1,255	4.18	2.91
6	3							Oil - G						
7	Crist 4	78.0	43,070	74.2	95.2	78.0	10,191	Coal	18,351	11,959	438,919	647,969	1.50	35.31
8	4							Gas - G						
9	Crist 5	80.0	40,090	67.4	95.7	70.4	10,473	Coal	17,555	11,959	419,880	619,884	1.55	35.31
10	5							Gas - G						
11	Crist 6	302.0	75,590	33.6	43.7	77.0	10,667	Coal	33,711	11,959	806,346	1,190,351	1.57	35.31
12	6							Gas - G						
13	Crist 7	465.0	287,810	83.2	91.9	90.5	10,237	Coal	123,186	11,959	2,946,414	4,349,670	1.51	35.31
14	7							Gas - G						
15	Scherer 3 (2)	214.1	72,640	45.6	65.6	69.5	10,245	Coal			744,199	1,374,365	1.89	#N/A
16	Scholz 1	46.0	9,670	28.3	92.7	30.5	13,091	Coal	4,996	12,669	126,589	207,222	2.14	41.48
17	Scholz 2	46.0	10,100	29.5	96.9	30.5	13,120	Coal	5,230	12,669	132,511	216,952	2.15	41.48
18	Smith 1	162.0	77,730	64.5	98.1	65.7	10,456	Coal	33,933	11,976	812,763	1,161,175	1.49	34.22
19	Smith 2	192.6	105,810	73.8	96.9	76.2	10,118	Coal	44,693	11,976	1,070,564	1,529,407	1.45	34.22
20	Smith A (CT)	31.6	230	1.0	99.9	1.0	13,657	Oil - G	539	138,653	3,141	10,507	4.57	19.49
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	239.0	150,840	84.8	92.9	91.3	10,245	Coal	79,186	9,758	1,545,397	2,229,884	1.48	28.16
23	Daniel 2 (1)	239.0	97,380	54.8	57.7	94.9	10,013	Coal	49,964	9,758	975,097	1,406,981	1.44	28.16
24	Gas,BL							Gas	6,244	1,030	6,432	18,134	#N/A	2.90
25	Ltr. Oil							Oil	1,344	139,281	7,862	26,611	#N/A	19.80
26		2,178.3	979,730	60.5	80.7	74.9	10,245				10,037,121	15,155,164	1.55	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	50	0.3	48.3	0.6	15,020	Gas - G	729	1,030	751	2,065	4.13	2.83
2	1							Oil - G						
3	Crist 2	24.0	30	0.2	48.3	0.4	15,133	Gas - G	441	1,030	454	1,248	4.16	2.83
4	2							Oil - G						
5	Crist 3	35.0	70	0.3	48.3	0.6	15,129	Gas - G	1,028	1,030	1,059	2,911	4.16	2.83
6	3							Oil - G						
7	Crist 4	78.0	42,240	77.8	95.1	81.8	10,137	Coal	17,877	11,976	428,190	632,141	1.50	35.36
8	4							Gas - G						
9	Crist 5	80.0	39,920	71.7	95.7	74.9	10,394	Coal	17,324	11,976	414,944	612,573	1.53	35.36
10	5							Gas - G						
11	Crist 6	302.0	16,740	8.0	9.8	81.3	10,657	Coal	7,448	11,976	178,394	263,364	1.57	35.36
12	6							Gas - G						
13	Crist 7	465.0	236,500	73.1	78.6	93.0	10,229	Coal	101,004	11,976	2,419,219	3,571,492	1.51	35.36
14	7							Gas - G						
15	Scherer 3 (2)	214.1	33,710	22.6	30.0	75.4	10,204	Coal			343,985	649,838	1.93	#N/A
16	Scholz 1	46.0	6,520	20.4	63.9	31.9	13,030	Coal	3,353	12,669	84,958	139,098	2.13	41.48
17	Scholz 2	46.0	9,960	31.1	96.8	32.1	13,045	Coal	5,128	12,669	129,926	212,694	2.14	41.48
18	Smith 1	162.0	36,610	32.5	44.0	73.8	10,342	Coal	15,783	11,994	378,603	549,733	1.50	34.83
19	Smith 2	192.6	105,540	78.7	97.0	81.2	10,081	Coal	44,356	11,994	1,063,968	1,544,908	1.46	34.83
20	Smith A (CT)	31.6	20	0.1	100.0	0.1	14,650	Oil - G	50	138,664	293	981	4.91	19.50
21	Other Generation		8,140									152,706	1.88	#N/A
22	Daniel 1 (1)	239.0	124,200	74.7	79.7	93.7	10,311	Coal	65,562	9,767	1,280,624	1,864,575	1.50	28.44
23	Daniel 2 (1)	239.0	128,280	77.1	80.7	95.6	10,093	Coal	66,281	9,767	1,294,669	1,885,026	1.47	28.44
24	Gas,BL							Gas	6,244	1,030	6,431	17,681	#N/A	2.83
25	Ltr. Oil							Oil	1,342	139,521	7,862	26,925	#N/A	20.07
26		2,178.3	788,530	52.0	64.1	81.1	10,189				8,034,330	12,129,959	1.54	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	50	0.3	100.0	0.3	17,320	Gas - G	841	1,030	866	2,380	4.76	2.83
2	1							Oil - G						
3	Crist 2	24.0	40	0.2	100.0	0.2	16,300	Gas - G	633	1,030	652	1,792	4.48	2.83
4	2							Oil - G						
5	Crist 3	35.0	110	0.4	100.0	0.4	14,455	Gas - G	1,543	1,030	1,590	4,371	3.97	2.83
6	3							Oil - G						
7	Crist 4	78.0	46,540	80.2	95.2	84.2	10,104	Coal	19,619	11,984	470,228	693,911	1.49	35.37
8	4							Gas - G						
9	Crist 5	80.0	45,100	75.8	95.7	79.2	10,335	Coal	19,448	11,984	466,130	687,885	1.53	35.37
10	5							Gas - G						
11	Crist 6	302.0	170,190	75.7	90.2	84.0	10,636	Coal	75,528	11,984	1,810,160	2,671,429	1.57	35.37
12	6							Gas - G						
13	Crist 7	465.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,984	0	0	#N/A	#N/A
14	7							Gas - G						
15	Scherer 3 (2)	214.1	122,610	77.0	96.9	79.4	10,181	Coal			1,248,273	2,292,463	1.87	#N/A
16	Scholz 1	46.0	14,180	41.4	95.0	43.6	12,274	Coal	6,944	12,532	174,044	293,296	2.07	42.24
17	Scholz 2	46.0	14,580	42.6	97.8	43.6	12,316	Coal	7,164	12,532	179,562	302,626	2.08	42.24
18	Smith 1	162.0	92,820	77.0	98.1	78.5	10,287	Coal	39,772	12,004	954,846	1,401,182	1.51	35.23
19	Smith 2	192.6	119,780	83.6	96.9	86.3	10,049	Coal	50,132	12,004	1,203,639	1,766,136	1.47	35.23
20	Smith A (CT)	31.6	30	0.1	100.0	0.1	13,800	Oil - G	71	138,680	414	1,387	4.62	19.52
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	239.0	0	0.0	0.0	#N/A	#N/A	Coal	0	9,730	0	0	#N/A	#N/A
23	Daniel 2 (1)	239.0	88,620	49.8	51.6	96.6	10,083	Coal	45,916	9,730	893,524	1,299,409	1.47	28.30
24	Gas,BL							Gas	2,836	1,030	2,921	8,030	#N/A	2.83
25	Ltr. Oil							Oil	1,082	139,691	6,347	22,018	#N/A	20.35
26		2,178.3	723,350	44.6	59.8	74.6	10,248				7,413,196	11,611,527	1.61	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	10	0.1	100.0	0.1	18,400	Gas - G	179	1,030	184	460	4.60	2.57
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	20	0.1	100.0	0.1	13,250	Gas - G	257	1,030	265	663	3.32	2.58
6	3							Oil - G						
7	Crist 4	78.0	43,910	78.2	95.1	82.2	10,137	Coal	18,561	11,991	445,130	656,859	1.50	35.39
8	4							Gas - G						
9	Crist 5	80.0	42,700	74.1	95.7	77.5	10,360	Coal	18,446	11,991	442,372	652,805	1.53	35.39
10	5							Gas - G						
11	Crist 6	302.0	158,340	72.8	90.3	80.6	10,465	Coal	69,095	11,991	1,656,974	2,445,282	1.54	35.39
12	6							Gas - G						
13	Crist 7	465.0	143,030	42.7	45.9	93.1	10,223	Coal	60,972	11,991	1,462,169	2,157,803	1.51	35.39
14	7							Gas - G						
15	Scherer 3 (2)	214.1	114,370	74.2	96.9	76.6	10,201	Coal			1,166,701	2,111,428	1.85	#N/A
16	Scholz 1	46.0	9,580	28.9	92.8	31.2	13,054	Coal	5,031	12,428	125,062	215,427	2.25	42.82
17	Scholz 2	46.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	12,428	0	0	#N/A	#N/A
18	Smith 1	162.0	78,510	67.3	87.8	76.7	10,203	Coal	33,345	12,011	801,014	1,183,088	1.51	35.48
19	Smith 2	192.6	104,130	75.1	90.4	83.1	10,067	Coal	43,637	12,011	1,048,279	1,548,233	1.49	35.48
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	103,390	56.3	64.8	86.9	10,270	Coal	52,789	10,057	1,061,831	1,588,946	1.54	30.10
23	Daniel 2 (1)	255.0	141,940	77.3	87.3	88.6	10,070	Coal	71,059	10,057	1,429,325	2,138,879	1.51	30.10
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,321	139,779	7,753	26,884	#N/A	20.36
26		2,210.3	948,350	59.6	77.2	77.2	10,179				9,653,490	14,900,797	1.57	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	40	0.2	100.0	0.2	15,850	Gas - G	616	1,030	634	1,585	3.96	2.57
2	1							Oil - G						
3	Crist 2	24.0	30	0.2	100.0	0.2	16,867	Gas - G	491	1,030	506	1,265	4.22	2.58
4	2							Oil - G						
5	Crist 3	35.0	60	0.2	100.0	0.2	14,317	Gas - G	834	1,030	859	2,149	3.58	2.58
6	3							Oil - G						
7	Crist 4	78.0	43,630	75.2	95.2	79.0	10,179	Coal	18,509	11,997	444,105	655,403	1.50	35.41
8	4							Gas - G						
9	Crist 5	80.0	41,930	70.4	95.7	73.6	10,427	Coal	18,221	11,997	437,195	645,207	1.54	35.41
10	5							Gas - G						
11	Crist 6	302.0	165,050	73.5	96.8	75.9	10,563	Coal	72,661	11,997	1,743,464	2,572,914	1.56	35.41
12	6							Gas - G						
13	Crist 7	465.0	283,920	82.1	91.9	89.3	10,377	Coal	122,785	11,997	2,946,183	4,347,828	1.53	35.41
14	7							Gas - G						
15	Scherer 3 (2)	214.1	107,510	67.5	96.9	69.7	10,250	Coal			1,101,970	1,981,436	1.84	#N/A
16	Scholz 1	46.0	11,660	34.1	95.2	35.8	12,400	Coal	5,855	12,348	144,582	253,299	2.17	43.26
17	Scholz 2	46.0	910	2.7	9.4	28.3	12,565	Coal	463	12,348	11,434	20,018	2.20	43.24
18	Smith 1	162.0	80,190	66.5	98.1	67.8	10,287	Coal	34,330	12,014	824,909	1,221,799	1.52	35.59
19	Smith 2	192.6	51,780	36.1	46.4	77.9	10,255	Coal	22,100	12,014	531,019	786,545	1.52	35.59
20	Smith A (CT)	31.6	30	0.1	100.0	0.1	12,667	Oil - G	65	138,695	380	1,274	4.25	19.53
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	129,640	68.3	92.9	73.6	10,418	Coal	65,395	10,326	1,350,589	2,065,828	1.59	31.59
23	Daniel 2 (1)	255.0	136,770	72.1	94.1	76.6	10,184	Coal	67,442	10,326	1,392,854	2,130,478	1.56	31.59
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,338	139,861	7,862	27,388	#N/A	20.46
26		2,210.3	1,061,850	64.6	88.9	72.6	10,307				10,944,976	16,893,709	1.59	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	1,830	10.6	99.0	10.7	18,260	Gas - G	32,443	1,030	33,416	83,556	4.57	2.58
2	1							Oil - G						
3	Crist 2	24.0	1,230	7.1	99.0	7.2	19,333	Gas - G	23,086	1,030	23,779	59,459	4.83	2.58
4	2							Oil - G						
5	Crist 3	35.0	3,440	13.7	99.0	13.8	16,377	Gas - G	54,695	1,030	56,336	140,867	4.09	2.58
6	3							Oil - G						
7	Crist 4	78.0	46,490	82.8	97.4	85.0	10,093	Coal	19,549	12,001	469,215	692,830	1.49	35.44
8	4							Gas - G						
9	Crist 5	80.0	45,230	78.5	97.6	80.5	10,318	Coal	19,443	12,001	466,671	689,066	1.52	35.44
10	5							Gas - G						
11	Crist 6	302.0	176,160	81.0	96.8	83.7	10,635	Coal	78,057	12,001	1,873,524	2,766,353	1.57	35.44
12	6							Gas - G						
13	Crist 7	465.0	302,170	90.3	91.9	98.2	10,198	Coal	128,386	12,001	3,081,395	4,549,967	1.51	35.44
14	7							Gas - G						
15	Scherer 3 (2)	214.1	118,600	76.9	97.1	79.2	10,183	Coal			1,207,704	2,148,972	1.81	#N/A
16	Scholz 1	46.0	16,950	51.2	93.9	54.5	12,401	Coal	8,566	12,269	210,200	374,344	2.21	43.70
17	Scholz 2	46.0	16,780	50.7	96.0	52.8	12,458	Coal	8,519	12,269	209,046	372,271	2.22	43.70
18	Smith 1	162.0	89,520	76.7	98.2	78.2	10,292	Coal	38,333	12,017	921,325	1,369,245	1.53	35.72
19	Smith 2	192.6	116,100	83.7	96.9	86.4	10,147	Coal	49,014	12,017	1,178,046	1,750,790	1.51	35.72
20	Smith A (CT)	31.6	20	0.1	100.0	0.1	10,850	Oil - G	37	138,703	217	727	3.64	19.52
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	142,210	77.5	92.9	83.4	10,127	Coal	68,260	10,550	1,440,228	2,239,609	1.57	32.81
23	Daniel 2 (1)	255.0	149,360	81.4	94.0	86.5	10,027	Coal	70,978	10,550	1,497,577	2,328,774	1.56	32.81
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,338	139,931	7,862	27,506	#N/A	20.56
26		2,210.3	1,234,510	77.6	95.2	81.5	10,274				12,682,972	19,768,376	1.60	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	5,250	29.4	97.4	30.2	17,873	Gas - G	91,100	1,030	93,833	251,254	4.79	2.76
2	1							Oil - G						
3	Crist 2	24.0	3,720	20.8	97.4	21.4	18,532	Gas - G	66,930	1,030	68,938	184,593	4.96	2.76
4	2							Oil - G						
5	Crist 3	35.0	9,780	37.6	97.4	38.6	16,142	Gas - G	153,269	1,030	157,867	422,716	4.32	2.76
6	3							Oil - G						
7	Crist 4	78.0	47,990	82.7	97.3	85.0	10,098	Coal	20,186	12,003	484,585	715,785	1.49	35.46
8	4							Gas - G						
9	Crist 5	80.0	47,420	79.7	97.7	81.5	10,306	Coal	20,357	12,003	488,690	721,859	1.52	35.46
10	5							Gas - G						
11	Crist 6	302.0	181,350	80.7	96.8	83.4	10,637	Coal	80,357	12,003	1,929,050	2,849,474	1.57	35.46
12	6							Gas - G						
13	Crist 7	465.0	309,690	89.5	91.9	97.4	10,202	Coal	131,610	12,003	3,159,446	4,666,887	1.51	35.46
14	7							Gas - G						
15	Scherer 3 (2)	214.1	123,390	77.5	97.0	79.9	10,182	Coal			1,256,326	2,252,376	1.83	#N/A
16	Scholz 1	46.0	18,390	53.7	94.0	57.2	12,363	Coal	9,327	12,188	227,355	411,886	2.24	44.16
17	Scholz 2	46.0	18,720	54.7	96.0	57.0	12,405	Coal	9,526	12,188	232,215	420,662	2.25	44.16
18	Smith 1	162.0	93,110	77.3	98.1	78.7	10,383	Coal	40,214	12,020	966,745	1,440,454	1.55	35.82
19	Smith 2	192.6	119,230	83.2	96.9	85.9	10,249	Coal	50,834	12,020	1,222,036	1,820,885	1.53	35.82
20	Smith A (CT)	31.6	270	1.1	100.0	1.1	14,081	Oil - G	652	138,839	3,802	12,827	4.75	19.67
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	146,580	77.3	92.9	83.2	10,204	Coal	69,662	10,735	1,495,693	2,354,579	1.61	33.80
23	Daniel 2 (1)	255.0	153,420	80.9	94.1	85.9	10,169	Coal	72,660	10,735	1,560,064	2,455,905	1.60	33.80
24	Gas,BL							Gas	6,244	1,030	6,431	17,221	#N/A	2.76
25	Ltr. Oil							Oil	1,335	140,188	7,862	28,096	#N/A	21.04
26		2,210.3	1,287,010	78.3	95.2	82.2	10,381				13,360,938	21,190,671	1.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	5,690	31.9	97.4	32.7	17,650	Gas - G	97,506	1,030	100,431	268,921	4.73	2.76
2	1							Oil - G						
3	Crist 2	24.0	3,990	22.3	97.4	22.9	18,238	Gas - G	70,650	1,030	72,770	194,852	4.88	2.76
4	2							Oil - G						
5	Crist 3	35.0	10,460	40.2	97.4	41.2	15,993	Gas - G	162,420	1,030	167,292	447,956	4.28	2.76
6	3							Oil - G						
7	Crist 4	78.0	48,980	84.4	97.3	86.7	10,069	Coal	20,541	12,005	493,189	729,189	1.49	35.50
8	4							Gas - G						
9	Crist 5	80.0	47,670	80.1	97.7	82.0	10,298	Coal	20,445	12,005	490,884	725,811	1.52	35.50
10	5							Gas - G						
11	Crist 6	302.0	187,870	83.6	96.8	86.4	10,625	Coal	83,140	12,005	1,996,150	2,951,465	1.57	35.50
12	6							Gas - G						
13	Crist 7	465.0	317,060	91.6	91.9	99.7	10,190	Coal	134,572	12,005	3,230,877	4,777,314	1.51	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	125,480	78.8	97.0	81.2	10,171	Coal			1,276,230	2,278,698	1.82	#N/A
16	Scholz 1	46.0	20,770	60.7	94.0	64.6	12,268	Coal	10,509	12,123	254,801	467,760	2.25	44.51
17	Scholz 2	46.0	20,910	61.1	96.0	63.6	12,311	Coal	10,617	12,123	257,425	472,558	2.26	44.51
18	Smith 1	162.0	95,770	79.5	98.1	81.0	10,264	Coal	40,884	12,022	982,975	1,467,329	1.53	35.89
19	Smith 2	192.6	124,300	86.7	96.9	89.5	10,209	Coal	52,779	12,022	1,268,977	1,894,236	1.52	35.89
20	Smith A (CT)	31.6	310	1.3	100.0	1.3	14,052	Oil - G	746	138,981	4,356	14,793	4.77	19.82
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	154,580	81.5	92.9	87.7	10,127	Coal	71,884	10,889	1,565,415	2,487,885	1.61	34.61
23	Daniel 2 (1)	255.0	161,730	85.2	94.1	90.6	10,113	Coal	75,108	10,889	1,635,628	2,599,492	1.61	34.61
24	Gas,BL							Gas	6,244	1,030	6,431	17,221	#N/A	2.76
25	Ltr. Oil							Oil	1,335	140,235	7,862	28,162	#N/A	21.10
26		2,210.3	1,334,270	81.1	95.2	85.3	10,351				13,811,693	21,986,854	1.65	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	2,700	15.6	98.1	15.9	19,290	Gas - G	50,566	1,030	52,083	130,233	4.82	2.58
2	1							Oil - G						
3	Crist 2	24.0	940	5.4	99.2	5.5	19,685	Gas - G	17,965	1,030	18,504	46,269	4.92	2.58
4	2							Oil - G						
5	Crist 3	35.0	5,410	21.5	98.1	21.9	16,958	Gas - G	89,070	1,030	91,742	229,399	4.24	2.58
6	3							Oil - G						
7	Crist 4	78.0	32,780	58.4	71.4	81.7	10,142	Coal	13,845	12,006	332,446	491,342	1.50	35.49
8	4							Gas - G						
9	Crist 5	80.0	43,430	75.4	97.6	77.3	10,368	Coal	18,752	12,006	450,273	665,493	1.53	35.49
10	5							Gas - G						
11	Crist 6	302.0	165,710	76.2	96.8	78.7	10,658	Coal	73,551	12,006	1,766,150	2,610,316	1.58	35.49
12	6							Gas - G						
13	Crist 7	465.0	263,500	78.7	85.8	91.7	10,232	Coal	112,273	12,006	2,696,023	3,984,610	1.51	35.49
14	7							Gas - G						
15	Scherer 3 (2)	214.1	111,040	72.0	97.1	74.2	10,218	Coal			1,134,634	2,029,017	1.83	#N/A
16	Scholz 1	46.0	11,190	33.8	68.9	49.0	12,494	Coal	5,782	12,090	139,809	258,464	2.31	44.70
17	Scholz 2	46.0	14,630	44.2	96.0	46.0	12,582	Coal	7,612	12,090	184,069	340,248	2.33	44.70
18	Smith 1	162.0	82,840	71.0	98.2	72.3	10,360	Coal	35,691	12,023	858,226	1,282,730	1.55	35.94
19	Smith 2	192.6	104,890	75.6	96.9	78.1	10,181	Coal	44,414	12,023	1,067,925	1,596,244	1.52	35.94
20	Smith A (CT)	31.6	50	0.2	100.0	0.2	13,480	Oil - G	115	139,003	674	2,291	4.58	19.84
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	131,000	71.4	92.9	76.8	10,239	Coal	60,894	11,013	1,341,282	2,148,320	1.64	35.28
23	Daniel 2 (1)	255.0	100,880	54.9	69.0	79.6	10,238	Coal	46,890	11,013	1,032,843	1,654,265	1.64	35.28
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,334	140,275	7,862	28,221	#N/A	21.15
26		2,210.3	1,079,410	67.8	89.6	75.7	10,358				11,180,976	17,671,502	1.64	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	12,007	0	0	#N/A	#N/A
8	4							Gas - G		1,030	0			
9	Crist 5	80.0	12,030	20.2	27.9	72.4	10,424	Coal	5,222	12,007	125,401	185,371	1.54	35.50
10	5							Gas - G						
11	Crist 6	302.0	168,540	75.0	96.8	77.5	10,666	Coal	74,855	12,007	1,797,568	2,657,336	1.58	35.50
12	6							Gas - G						
13	Crist 7	465.0	273,560	79.1	86.0	91.9	10,231	Coal	116,547	12,007	2,798,816	4,137,445	1.51	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	115,190	72.3	96.9	74.6	10,212	Coal			1,176,310	2,094,343	1.82	#N/A
16	Scholz 1	46.0	6,670	19.5	91.8	21.2	13,095	Coal	3,622	12,056	87,342	162,597	2.44	44.89
17	Scholz 2	46.0	5,350	15.6	69.4	22.5	13,138	Coal	2,915	12,056	70,286	130,849	2.45	44.89
18	Smith 1	162.0	86,390	71.7	98.1	73.1	10,352	Coal	37,190	12,023	894,271	1,338,474	1.55	35.99
19	Smith 2	192.6	111,330	77.7	96.9	80.2	10,089	Coal	46,710	12,023	1,123,259	1,681,087	1.51	35.99
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	69,530	36.6	45.0	81.4	10,164	Coal	31,831	11,101	706,721	1,137,959	1.64	35.75
23	Daniel 2 (1)	255.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,101	0	0	#N/A	#N/A
24	Gas,BL							Gas	5,523	1,030	5,689	14,224	#N/A	2.58
25	Ltr. Oil							Oil	1,114	140,275	6,566	23,593	#N/A	21.17
26		2,210.3	857,290	52.1	71.1	73.3	10,256				8,792,229	13,726,490	1.60	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	25,240	44.9	60.4	74.4	10,237	Coal	10,759	12,008	258,388	381,844	1.51	35.49
8	4							Gas - G						
9	Crist 5	80.0	26,580	46.1	96.9	47.6	10,488	Coal	11,608	12,008	278,778	411,968	1.55	35.49
10	5							Gas - G						
11	Crist 6	302.0	155,990	71.7	96.8	74.1	10,682	Coal	69,380	12,008	1,666,280	2,462,282	1.58	35.49
12	6							Gas - G						
13	Crist 7	465.0	271,500	81.1	85.8	94.5	10,217	Coal	115,494	12,008	2,773,804	4,098,889	1.51	35.49
14	7							Gas - G						
15	Scherer 3 (2)	214.1	106,610	69.2	96.9	71.4	10,223	Coal			1,089,910	1,949,136	1.83	#N/A
16	Scholz 1	46.0	6,390	19.3	95.1	20.3	13,096	Coal	3,477	12,034	83,684	156,490	2.45	45.01
17	Scholz 2	46.0	6,660	20.1	97.9	20.5	13,129	Coal	3,633	12,034	87,441	163,531	2.46	45.01
18	Smith 1	162.0	56,690	48.6	68.8	70.6	10,242	Coal	24,145	12,024	580,639	869,705	1.53	36.02
19	Smith 2	192.6	87,460	63.1	77.5	81.4	10,080	Coal	36,662	12,024	881,626	1,320,563	1.51	36.02
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	94,140	51.3	65.0	78.9	10,186	Coal	42,997	11,151	958,919	1,548,313	1.64	36.01
23	Daniel 2 (1)	255.0	114,890	62.6	78.3	79.9	10,027	Coal	51,655	11,151	1,152,036	1,860,088	1.62	36.01
24	Gas,BL							Gas	6,244	1,030	6,431	17,681	#N/A	2.83
25	Ltr. Oil							Oil	1,334	140,338	7,862	28,313	#N/A	21.23
26		2,210.3	960,570	60.4	83.8	72.0	10,229				9,825,798	15,426,762	1.61	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	0.0	#N/A	Gas - G	20	1,030	21	58	#N/A	2.90
6	3							Oil - G						
7	Crist 4	78.0	40,130	69.2	95.3	72.6	10,276	Coal	17,170	12,009	412,389	609,528	1.52	35.50
8	4							Gas - G						
9	Crist 5	80.0	36,400	61.2	95.7	63.9	10,598	Coal	16,062	12,009	385,777	570,209	1.57	35.50
10	5							Gas - G						
11	Crist 6	302.0	153,380	68.3	96.8	70.5	10,701	Coal	68,339	12,009	1,641,366	2,426,050	1.58	35.50
12	6							Gas - G						
13	Crist 7	465.0	258,420	74.7	86.0	86.9	10,259	Coal	110,387	12,009	2,651,218	3,918,722	1.52	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	99,580	62.5	96.9	64.5	10,282	Coal			1,023,886	1,841,512	1.85	#N/A
16	Scholz 1	46.0	6,600	19.3	95.0	20.3	13,089	Coal	3,593	12,022	86,390	161,978	2.45	45.08
17	Scholz 2	46.0	6,880	20.1	97.8	20.6	13,128	Coal	3,756	12,022	90,318	169,315	2.46	45.08
18	Smith 1	162.0	73,070	60.6	98.1	61.8	10,526	Coal	31,983	12,024	769,127	1,152,672	1.58	36.04
19	Smith 2	192.6	82,970	57.9	81.3	71.2	10,160	Coal	35,051	12,024	842,942	1,263,233	1.52	36.04
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	122,360	64.5	92.9	69.4	10,316	Coal	56,413	11,188	1,262,297	2,042,699	1.67	36.21
23	Daniel 2 (1)	255.0	128,550	67.8	94.1	72.0	10,126	Coal	58,180	11,188	1,301,754	2,106,678	1.64	36.21
24	Gas,BL							Gas	6,244	1,030	6,431	18,134	#N/A	2.90
25	Ltr. Oil							Oil	1,334	140,368	7,862	28,352	#N/A	21.26
26		2,210.3	1,017,040	61.8	92.6	66.8	10,306				10,481,778	16,472,352	1.62	

Notes:
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SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2000 - DECEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	15,640	7.4	95.2	7.8	18,063	Gas - G	274,285		282,512	741,340	4.74	2.70
2	1							Oil - G	0		0			
3	Crist 2	24.0	10,000	4.7	95.3	5.0	18,585	Gas - G	180,437	1,030	185,851	490,177	4.90	2.72
4	2							Oil - G	0		0			
5	Crist 3	35.0	29,380	9.6	95.2	10.0	16,252	Gas - G	463,568	1,030	477,476	1,252,345	4.26	2.70
6	3							Oil - G	0		0			
7	Crist 4	78.0	461,000	67.3	82.8	81.3	10,145	Coal	194,967	11,994	4,676,784	6,906,801	1.50	35.43
8	4							Gas - G	0		0			
9	Crist 5	80.0	468,500	66.7	90.7	73.5	10,388	Coal	202,883	11,995	4,866,995	7,188,131	1.53	35.43
10	5							Gas - G	0		0			
11	Crist 6	302.0	1,774,910	66.9	84.3	79.4	10,629	Coal	786,122	11,999	18,865,426	27,866,616	1.57	35.45
12	6							Gas - G	0		0	0		
13	Crist 7	465.0	2,947,160	72.2	77.3	93.3	10,235	Coal	1,257,216	11,997	30,165,564	44,560,627	1.51	35.44
14	7							Gas - G	0		0			
15	Scherer 3 (2)	214.1	1,250,730	66.5	89.0	74.7	10,210	Coal			12,770,128	23,003,584	1.84	#N/A
16	Scholz 1	46.0	138,570	34.3	89.5	38.3	12,592	Coal	71,055	12,278	1,744,816	3,101,861	2.24	43.65
17	Scholz 2	46.0	125,480	31.1	79.2	39.2	12,625	Coal	64,563	12,269	1,584,233	2,821,724	2.25	43.70
18	Smith 1	162.0	943,250	66.3	90.6	73.2	10,332	Coal	405,603	12,014	9,745,443	14,437,586	1.53	35.60
19	Smith 2	192.6	1,233,320	72.9	89.2	81.7	10,137	Coal	520,382	12,013	12,502,280	18,502,267	1.50	35.56
20	Smith A (CT)	31.6	960	0.3	100.0	0.3	13,830	Oil - G	2,275	138,981	13,277	44,787	4.67	19.69
21	Other Generation		102,720									1,927,026	1.88	#N/A
22	Daniel 1 (1)	251.0	1,368,470	62.1	75.3	82.4	10,237	Coal	664,873	10,535	14,008,996	21,708,597	1.59	32.65
23	Daniel 2 (1)	251.0	1,401,820	63.6	74.5	85.3	10,105	Coal	676,133	10,475	14,165,371	21,865,975	1.56	32.34
24	Gas,BL							Gas	70,799	0	72,921	192,650	#N/A	2.72
25	Ltr. Oil							Oil	15,551	139,978	91,424	322,069	#N/A	20.71
26		2,202.3	12,271,910	63.4	82.8	76.6	10,285				126,219,497	196,934,163	1.60	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
15	*PURCHASES :*													
16	UNITS (BBL)	1,508	997	905	977	994	1,006	1,329	1,325	1,327	1,107	1,326	1,326	14,127
17	UNIT COST ($/BBL)	21.80	21.62	21.62	21.61	21.62	21.62	21.58	21.58	21.57	21.59	21.58	21.57	21.62
18	AMOUNT ($)	32,868	21,559	19,570	21,114	21,489	21,749	28,679	28,594	28,626	23,900	28,614	28,607	305,369
20	*BURNED :*													
21	UNITS (BBL)	1,344	1,342	1,082	1,321	1,338	1,338	1,335	1,335	1,334	1,114	1,334	1,334	15,551
22	UNIT COST ($/BBL)	19.80	20.06	20.35	20.35	20.47	20.56	21.05	21.10	21.16	21.18	21.22	21.25	20.71
23	AMOUNT ($)	26,611	26,925	22,018	26,884	27,388	27,506	28,096	28,162	28,221	23,593	28,313	28,352	322,069
24	*ENDING INVENTORY :*													
25	UNITS (BBL)	7,647	7,302	7,125	6,781	6,437	6,105	6,099	6,089	6,082	6,075	6,067	6,059	
26	UNIT COST ($/BBL)	19.69	19.88	20.03	20.20	20.36	20.52	20.64	20.74	20.83	20.91	20.99	21.06	
27	AMOUNT ($)	150,537	145,171	142,723	136,953	131,054	125,297	125,880	126,312	126,717	127,024	127,325	127,580	
29	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
30	*PURCHASES :*													
31	UNITS (TONS)	542,000	436,761	272,028	376,434	409,357	423,213	437,758	446,920	386,267	406,494	396,505	407,688	4,941,425
32	UNIT COST ($/TON)	34.27	33.46	34.54	36.21	36.10	36.21	36.24	36.25	36.13	36.18	36.18	36.18	35.65
33	AMOUNT ($)	18,575,569	14,613,315	9,396,676	13,629,827	14,778,417	15,322,642	15,864,082	16,200,811	13,955,422	14,706,555	14,345,535	14,751,529	176,140,380
34	*BURNED :*													
35	UNITS (TONS)	410,805	344,116	264,523	372,935	427,761	489,105	504,733	520,479	419,704	318,892	369,810	400,934	4,843,797
36	UNIT COST ($/TON)	33.01	32.77	34.46	33.75	34.36	35.03	35.38	35.68	35.82	35.85	35.89	35.97	34.88
37	AMOUNT ($)	13,559,495	11,275,604	9,115,874	12,587,322	14,699,319	17,133,249	17,858,376	18,573,039	15,032,032	11,431,118	13,273,673	14,421,084	168,960,185
38	*ENDING INVENTORY :*													
39	UNITS (TONS)	1,095,494	1,188,139	1,195,644	1,199,143	1,180,739	1,114,847	1,047,872	974,313	940,876	1,028,478	1,055,173	1,061,927	
40	UNIT COST ($/TON)	32.68	32.95	32.97	33.75	34.34	34.75	35.06	35.28	35.38	35.56	35.67	35.76	
41	AMOUNT ($)	35,806,178	39,143,889	39,424,691	40,467,196	40,546,294	38,735,687	36,741,393	34,369,165	33,292,555	36,567,992	37,639,854	37,970,299	
43	DAYS SUPPLY:	48	52	52	52	52	49	46	43	41	45	46	46	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
44	*PURCHASES :*													
45	UNITS (MMBTU)	744,802	396,132	1,264,748	1,184,950	1,129,192	1,263,552	1,061,681	1,205,301	1,103,279	1,217,363	1,111,568	1,028,365	12,710,933
46	UNIT COST ($/MMBTU)	1.92	1.99	1.79	1.79	1.79	1.76	1.81	1.78	1.79	1.77	1.79	1.81	1.80
47	AMOUNT ($)	1,430,479	788,652	2,270,195	2,116,834	2,018,468	2,228,147	1,919,225	2,145,291	1,975,047	2,160,792	1,994,753	1,858,921	22,906,804
48	*BURNED :*													
49	UNITS (MMBTU)	744,199	343,985	1,248,273	1,166,701	1,101,970	1,207,704	1,256,326	1,276,230	1,134,634	1,176,310	1,089,910	1,023,886	12,770,128
50	UNIT COST ($/MMBTU)	1.85	1.89	1.84	1.81	1.80	1.78	1.79	1.79	1.79	1.78	1.79	1.80	1.80
51	AMOUNT ($)	1,374,365	649,838	2,292,463	2,111,428	1,981,436	2,148,972	2,252,376	2,278,698	2,029,017	2,094,343	1,949,136	1,841,512	23,003,584
52	*ENDING INVENTORY :*													
53	UNITS (MMBTU)	951,591	1,003,738	1,020,213	1,038,462	1,065,684	1,121,532	926,887	855,958	824,603	865,656	887,314	891,793	
54	UNIT COST ($/MMBTU)	1.85	1.89	1.84	1.81	1.80	1.78	1.79	1.79	1.79	1.78	1.79	1.80	
55	AMOUNT ($)	1,757,137	1,895,951	1,873,683	1,879,089	1,916,121	1,995,296	1,662,145	1,528,738	1,474,768	1,541,217	1,586,834	1,604,243	
57	DAYS SUPPLY:	22	23	23	24	24	25	21	19	19	20	20	20	
	GAS													
58	*BURNED :*													
59	UNITS (MCF)	7,222	8,442	5,853	6,680	8,185	116,468	317,543	336,820	163,845	5,523	6,244	6,264	989,089
60	UNIT COST ($/MCF)	2.90	2.83	2.83	2.58	2.58	2.58	2.76	2.76	2.58	2.58	2.83	2.90	2.71
61	AMOUNT ($)	20,974	23,905	16,573	17,204	21,080	299,963	875,784	928,950	421,982	14,224	17,681	18,192	2,676,512
	OTHER - C.T. OIL													
62	*PURCHASES :*													
63	UNITS (BBL)	658	50	71	0	65	37	653	746	115	0	0	0	2,395
64	UNIT COST ($/BBL)	21.53	21.36	21.56	#N/A	21.60	21.68	21.52	21.54	21.46	#N/A	#N/A	#N/A	21.53
65	AMOUNT ($)	14,165	1,068	1,531	0	1,404	802	14,055	16,072	2,468	0	0	0	51,565
66	*BURNED :*													
67	UNITS (BBL)	539	50	71	0	65	37	652	746	115	0	0	0	2,275
68	UNIT COST ($/BBL)	19.49	19.62	19.54	#N/A	19.60	19.65	19.67	19.83	19.92	#N/A	#N/A	#N/A	19.69
69	AMOUNT ($)	10,507	981	1,387	0	1,274	727	12,827	14,793	2,291	0	0	0	44,787
70	*ENDING INVENTORY :*													
71	UNITS (BBL)	8,570	8,570	8,570	8,570	8,570	8,570	8,571	8,571	8,571	8,571	8,571	8,571	
72	UNIT COST ($/BBL)	19.48	19.49	19.51	19.51	19.53	19.54	19.68	19.83	19.85	19.85	19.85	19.85	
73	AMOUNT ($)	166,983	167,070	167,214	167,214	167,344	167,419	168,647	169,926	170,103	170,103	170,103	170,103	
75	DAYS SUPPLY:	107	107	107	107	107	107	107	107	107	107	107	107	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
			KWH		¢ / KWH		TOTAL $	
	MONTH	TOTAL	WHEELED	KWH	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	COST	COST	ADJUSTMENT	$
	JANUARY							
1	Southern Co. Interchange	93,944,000	0	93,944,000	1.40	1.61	1,319,000	1,513,000
2	Unit Power Sales	42,890,000	0	42,890,000	2.00	2.12	856,000	908,000
3	Economy Sales	3,310,000	0	3,310,000	2.96	2.99	98,000	99,000
4	80% Gain on Economy Sales						10,000	12,000
5	Other Sales	200,000		200,000	2.00	2.00	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	140,344,000	0	140,344,000	1.63	1.81	2,287,000	2,536,000
	FEBRUARY							
1	Southern Co. Interchange	70,946,000	0	70,946,000	1.49	1.67	1,060,000	1,182,000
2	Unit Power Sales	35,680,000	0	35,680,000	1.98	2.10	705,000	748,000
3	Economy Sales	4,180,000	0	4,180,000	2.89	2.94	121,000	123,000
4	80% Gain on Economy Sales						12,000	15,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	110,996,000	0	110,996,000	1.71	1.87	1,902,000	2,072,000
	MARCH							
1	Southern Co. Interchange	41,798,000	0	41,798,000	1.63	1.81	680,000	756,000
2	Unit Power Sales	78,000,000	0	78,000,000	1.94	2.09	1,517,000	1,627,000
3	Economy Sales	18,880,000	0	18,880,000	2.58	2.68	488,000	506,000
4	80% Gain on Economy Sales						49,000	61,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	138,868,000	0	138,868,000	1.97	2.13	2,738,000	2,954,000
	APRIL							
1	Southern Co. Interchange	153,236,000	0	153,236,000	1.58	1.78	2,417,000	2,728,000
2	Unit Power Sales	37,920,000	0	37,920,000	1.85	1.97	700,000	748,000
3	Economy Sales	22,410,000	0	22,410,000	2.63	2.70	589,000	604,000
4	80% Gain on Economy Sales						58,000	72,000
5	Other Sales	190,000		190,000	1.58	1.58	3,000	3,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	213,756,000	0	213,756,000	1.76	1.94	3,767,000	4,155,000
	MAY							
1	Southern Co. Interchange	107,866,000	0	107,866,000	1.89	2.11	2,042,000	2,277,000
2	Unit Power Sales	71,680,000	0	71,680,000	1.91	2.04	1,366,000	1,460,000
3	Economy Sales	5,680,000	0	5,680,000	2.87	2.90	163,000	165,000
4	80% Gain on Economy Sales						16,000	20,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	185,416,000	0	185,416,000	1.94	2.12	3,591,000	3,926,000
	JUNE							
1	Southern Co. Interchange	107,051,000	0	107,051,000	1.97	2.18	2,107,000	2,333,000
2	Unit Power Sales	87,590,000	0	87,590,000	1.88	2.01	1,649,000	1,762,000
3	Economy Sales	9,320,000	0	9,320,000	3.04	3.13	283,000	292,000
4	80% Gain on Economy Sales						28,000	35,000
5	Other Sales	180,000		180,000	2.22	2.78	4,000	5,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	204,141,000	0	204,141,000	1.99	2.17	4,071,000	4,427,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
MONTH		KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JULY							
1	Southern Co. Interchange	126,590,000	0	126,590,000	2.44	2.65	3,083,000	3,357,000
2	Unit Power Sales	101,360,000	0	101,360,000	1.90	2.03	1,930,000	2,062,000
3	Economy Sales	14,190,000	0	14,190,000	3.33	3.46	472,000	491,000
4	80% Gain on Economy Sales						47,000	59,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	242,330,000	0	242,330,000	2.28	2.46	5,536,000	5,973,000
	AUGUST							
1	Southern Co. Interchange	164,683,000	0	164,683,000	2.36	2.58	3,883,000	4,252,000
2	Unit Power Sales	94,940,000	0	94,940,000	1.90	2.03	1,802,000	1,925,000
3	Economy Sales	8,170,000	0	8,170,000	3.38	3.53	276,000	288,000
4	80% Gain on Economy Sales						28,000	35,000
5	Other Sales	190,000		190,000	2.63	2.63	5,000	5,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	267,983,000	0	267,983,000	2.24	2.43	5,994,000	6,505,000
	SEPTEMBER							
1	Southern Co. Interchange	105,072,000	0	105,072,000	2.00	2.21	2,101,000	2,327,000
2	Unit Power Sales	70,740,000	0	70,740,000	1.90	2.03	1,341,000	1,436,000
3	Economy Sales	7,970,000	0	7,970,000	2.79	2.89	222,000	230,000
4	80% Gain on Economy Sales						22,000	28,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	183,972,000	0	183,972,000	2.01	2.19	3,690,000	4,025,000
	OCTOBER							
1	Southern Co. Interchange	89,753,000	0	89,753,000	1.56	1.74	1,398,000	1,558,000
2	Unit Power Sales	31,040,000	0	31,040,000	1.79	1.91	555,000	594,000
3	Economy Sales	37,370,000	0	37,370,000	1.73	1.88	646,000	702,000
4	80% Gain on Economy Sales						67,000	84,000
5	Other Sales	190,000		190,000	1.58	1.58	3,000	3,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	158,353,000	0	158,353,000	1.69	1.86	2,669,000	2,941,000
	NOVEMBER							
8	Southern Co. Interchange	170,986,000	0	170,986,000	1.43	1.63	2,440,000	2,782,000
9	Unit Power Sales	35,880,000	0	35,880,000	1.75	1.85	628,000	665,000
10	Economy Sales	37,590,000	0	37,590,000	1.70	1.84	639,000	693,000
11	80% Gain on Economy Sales						67,000	83,000
12	Other Sales	180,000		180,000	1.67	1.67	3,000	3,000
13	SEPA	0	0	0	#N/A	#N/A	0	0
14	TOTAL ESTIMATED SALES	244,636,000	0	244,636,000	1.54	1.73	3,777,000	4,226,000
	DECEMBER							
15	Southern Co. Interchange	159,670,000	0	159,670,000	1.43	1.64	2,291,000	2,613,000
16	Unit Power Sales	41,450,000	0	41,450,000	1.84	1.97	761,000	818,000
17	Economy Sales	19,960,000	0	19,960,000	1.79	1.90	358,000	379,000
18	80% Gain on Economy Sales						36,000	45,000
19	Other Sales	190,000		190,000	1.58	2.11	3,000	4,000
20	SEPA	0	0	0	#N/A	#N/A	0	0
21	TOTAL ESTIMATED SALES	221,270,000	0	221,270,000	1.56	1.74	3,449,000	3,859,000
	TOTAL							
22	Southern Co. Interchange	1,391,595,000	0	1,391,595,000	1.78	1.99	24,821,000	27,678,000
23	Unit Power Sales	729,170,000	0	729,170,000	1.89	2.02	13,810,000	14,753,000
24	Economy Sales	189,030,000	0	189,030,000	2.30	2.42	4,355,000	4,572,000
25	80% Gain on Economy Sales						440,000	549,000
26	Other Sales	2,270,000	0	2,270,000	1.98	2.07	45,000	47,000
27	SEPA	0	0	0	#N/A	#N/A	0	0
28	TOTAL ESTIMATED SALES	2,312,065,000	0	2,312,065,000	1.88	2.06	43,471,000	47,599,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢/KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				260,000	1.661	1.661	4,319
FEBRUARY	Solutia	COG-1				40,000	1.661	1.661	664
MARCH	Solutia	COG-1				220,000	1.661	1.661	3,654
APRIL	Solutia	COG-1				260,000	2.324	2.324	6,042
MAY	Solutia	COG-1				570,000	2.324	2.324	13,247
JUNE	Solutia	COG-1				810,000	2.324	2.324	18,824
JULY	Solutia	COG-1				2,900,000	2.324	2.324	67,396
AUGUST	Solutia	COG-1				3,380,000	2.324	2.324	78,551
SEPTEMBER	Solutia	COG-1				530,000	2.324	2.324	12,317
OCTOBER	Solutia	COG-1				160,000	2.324	2.324	3,718
NOVEMBER	Solutia	COG-1				-	1.745	1.745	0
DECEMBER	Solutia	COG-1				-	1.745	1.745	0
TOTAL			0			9,130,000			208,732

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY				
1		Southern Co. Interchange	60,190,000	2.26	1,358,000
2		Unit Power Sales	4,670,000	2.25	105,000
3		Economy Energy	2,250,000	2.67	60,000
4		Other Purchases	4,360,000	3.49	152,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	71,470,000	2.34	1,675,000
	FEBRUARY				
1		Southern Co. Interchange	55,710,000	1.65	917,000
2		Unit Power Sales	5,880,000	2.09	123,000
3		Economy Energy	2,210,000	2.71	60,000
4		Other Purchases	3,750,000	3.44	129,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	67,550,000	1.82	1,229,000
	MARCH				
1		Southern Co. Interchange	195,000,000	1.94	3,785,000
2		Unit Power Sales	3,890,000	1.85	72,000
3		Economy Energy	3,220,000	3.20	103,000
4		Other Purchases	7,980,000	3.45	275,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	210,090,000	2.02	4,235,000
	APRIL				
1		Southern Co. Interchange	38,600,000	1.58	611,000
2		Unit Power Sales	4,660,000	1.80	84,000
3		Economy Energy	8,080,000	3.38	273,000
4		Other Purchases	4,920,000	3.29	162,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	56,260,000	2.01	1,130,000
	MAY				
1		Southern Co. Interchange	49,670,000	1.69	838,000
2		Unit Power Sales	1,070,000	2.43	26,000
3		Economy Energy	4,400,000	2.86	126,000
4		Other Purchases	4,540,000	3.44	156,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	59,680,000	1.92	1,146,000
	JUNE				
1		Southern Co. Interchange	31,440,000	1.79	564,000
2		Unit Power Sales	1,840,000	2.45	45,000
3		Economy Energy	4,760,000	2.98	142,000
4		Other Purchases	32,270,000	8.38	2,705,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	70,310,000	4.92	3,456,000

ECONOMY ENERGY PURCHASES

GULF POWER COMPANY

ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)
LINE	MONTH / TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	60,190,000	2.26	1,358,000
2	Unit Power Sales	4,670,000	2.25	105,000
3	Economy Energy	2,250,000	2.67	60,000
4	Other Purchases	4,360,000	3.49	152,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	71,470,000	2.34	1,675,000
	FEBRUARY			
1	Southern Co. Interchange	55,710,000	1.65	917,000
2	Unit Power Sales	5,880,000	2.09	123,000
3	Economy Energy	2,210,000	2.71	60,000
4	Other Purchases	3,750,000	3.44	129,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	67,550,000	1.82	1,229,000
	MARCH			
1	Southern Co. Interchange	195,000,000	1.94	3,785,000
2	Unit Power Sales	3,890,000	1.85	72,000
3	Economy Energy	3,220,000	3.20	103,000
4	Other Purchases	7,980,000	3.45	275,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	210,090,000	2.02	4,235,000
	APRIL			
1	Southern Co. Interchange	38,600,000	1.58	611,000
2	Unit Power Sales	4,660,000	1.80	84,000
3	Economy Energy	8,080,000	3.38	273,000
4	Other Purchases	4,920,000	3.29	162,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	56,260,000	2.01	1,130,000
	MAY			
1	Southern Co. Interchange	49,670,000	1.69	838,000
2	Unit Power Sales	1,070,000	2.43	26,000
3	Economy Energy	4,400,000	2.86	126,000
4	Other Purchases	4,540,000	3.44	156,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	59,680,000	1.92	1,146,000
	JUNE			
1	Southern Co. Interchange	31,440,000	1.79	564,000
2	Unit Power Sales	1,840,000	2.45	45,000
3	Economy Energy	4,760,000	2.98	142,000
4	Other Purchases	32,270,000	8.38	2,705,000
5	SEPA	0	#N/A	0
6	TOTAL ESTIMATED PURCHASES	70,310,000	4.92	3,456,000

Schedule E-10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Base Rate Revenues	$	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	566.76
Fuel Factor	¢/KWH	1.867	1.816	1.929	1.824	1.808	2.019	2.223	2.215	1.908	1.849	1.907	1.888	1.954
Group Loss Multiplier		1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228
Fuel Adjustment Revenues	$	18.90	18.38	19.53	18.46	18.30	20.44	22.50	22.42	19.31	18.72	19.30	19.11	235.37
TOTAL REVENUES	$	66.13	65.61	66.76	65.69	65.53	67.67	69.73	69.65	66.54	65.95	66.53	66.34	805.10

*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2000	JANUARY	1.661
	FEBRUARY	1.661
	MARCH	1.661
	APRIL	2.324
	MAY	2.324
	JUNE	2.324
	JULY	2.324
	AUGUST	2.324
	SEPTEMBER	2.324
	OCTOBER	2.324
	NOVEMBER	1.745
	DECEMBER	1.745
2001	JANUARY	1.745
	FEBRUARY	1.745
	MARCH	1.745
	APRIL	2.349
	MAY	2.349
	JUNE	2.349
	JULY	2.349
	AUGUST	2.349
	SEPTEMBER	2.349
	OCTOBER	2.349
	NOVEMBER	1.778
	DECEMBER	1.778

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 1997 - DECEMBER 2000

LINE	LINE DESCRIPTION	YEAR 1997	1998	1999	2000	DIFFERENCE (%) FROM PRIOR PERIOD 1997 to 1998	1998 to 1999	1999 to 2000
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
2	LIGHTER OIL	386,593	364,122	392,387	322,069	(5.81)	7.76	(17.92)
3	COAL	185,356,130	166,226,834	166,188,239	168,960,185	(10.32)	(0.02)	1.67
3a	COAL at Scherer	21,509,221	20,791,702	20,044,252	23,003,584	(3.34)	(3.59)	14.76
4	GAS	1,253,954	3,485,743	3,344,750	2,483,862	177.98	(4.04)	(25.74)
4a	GAS (B.L.)	315,971	73	0	192,650	(99.98)	(100.00)	#N/A
6	OTHER - C.T.	49,883	155,984	171,403	44,787	212.70	9.88	(73.87)
6a	OTHER GENERATION	0	498,557	1,981,161	1,927,026	#N/A	297.38	(2.73)
7	TOTAL ($)	208,871,752	191,523,015	192,122,192	196,934,163	(8.31)	0.31	2.50
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
9	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
10	COAL	10,800,620	11,557,450	12,334,820	12,113,210	7.01	6.73	(1.80)
11	GAS	22,580	96,120	103,260	55,020	325.69	7.43	(46.72)
13	OTHER - C.T.	830	2,340	2,490	960			
13	OTHER GENERATION	0	32,290	123,900	102,720	#N/A	283.71	(17.09)
14	TOTAL (MWH)	10,824,030	11,688,200	12,564,470	12,271,910	7.98	7.50	(2.33)
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	0	0	0	0	#N/A	#N/A	#N/A
16	LIGHTER OIL (BBL)	16,990	13,751	13,445	15,551	(19.06)	(2.23)	15.66
17	COAL excl. Scherer (TON)	4,523,720	4,827,753	5,247,061	4,843,797	6.72	8.69	(7.69)
18	GAS (MCF)	640,532	1,379,160	1,458,111	989,089	115.31	5.72	(32.17)
20	OTHER - C.T.	2,005	5,599	5,978	2,275	179.25	6.77	(61.94)
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
22	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
23	COAL + GAS B.L. + OIL B.L.	112,845,802	120,501,564	128,393,814	125,260,381	6.78	6.55	(2.44)
24	GAS - Generation	552,879	1,420,511	1,501,853	945,839	156.93	5.73	(37.02)
26	OTHER - C.T.	11,740	32,882	35,115	13,277	180.09	6.79	(62.19)
27	TOTAL (MMBTU)	113,410,421	121,954,957	129,930,782	126,219,497	7.53	6.54	(2.86)
	GENERATION MIX (% MWH)							
28	HEAVY OIL	0.00	0.00	0.00	0.00	#N/A	#N/A	#N/A
29	LIGHTER OIL	0.00	0.00	0.00	0.00	#N/A	#N/A	#N/A
30	COAL + GAS B.L. + OIL B.L.	99.78	98.88	98.17	98.70	(0.90)	(0.72)	0.54
31	GAS - Generation	0.21	0.82	0.82	0.45	290.48	0.00	(45.12)
33	OTHER - C.T.	0.01	0.02	0.02	0.01	100.00	0.00	(50.00)
33a	OTHER GENERATION	0.00	0.28	0.99	0.84	#N/A	253.57	(15.15)
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
35	HEAVY OIL ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
36	LIGHTER OIL B.L. ($/BBL)	22.75	26.48	29.18	20.71	16.40	10.20	(29.03)
37	COAL ($/TON)	40.97	34.43	31.67	34.88	(15.96)	(8.02)	10.14
38	GAS +B.L. ($/MCF)	2.45	2.53	2.29	2.71	3.27	(9.49)	18.34
40	OTHER - C.T.	24.88	27.86	28.67	19.69	11.98	2.91	(31.32)
	FUEL COST ($) / MMBTU							
41	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.84	1.56	1.45	1.54	(15.22)	(7.05)	6.21
44	GAS - Generation	2.27	2.45	2.23	2.63	7.93	(8.98)	17.94
46	OTHER - C.T.	4.25	4.74	4.88	3.37	11.53	2.95	(30.94)
47	TOTAL ($/MMBTU)	1.84	1.57	1.46	1.54	(14.67)	(7.01)	5.48
	BTU BURNED / KWH							
48	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,448	10,426	10,409	10,341	(0.21)	(0.16)	(0.65)
51	GAS - Generation	24,485	14,779	14,544	17,191	(39.64)	(1.59)	18.20
53	OTHER - C.T.	14,145	14,052	14,102	13,830	(0.66)	0.36	(1.93)
54	TOTAL (BTU/KWH)	10,478	10,434	10,341	10,285	(0.42)	(0.89)	(0.54)
	FUEL COST (¢ / KWH)							
55	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.92	1.62	1.51	1.59	(15.63)	(6.79)	5.30
58	GAS - Generation	5.55	3.63	3.24	4.51	(34.59)	(10.74)	39.20
60	OTHER - C.T.	6.01	6.67	6.88	4.67	10.98	3.15	(32.12)
60a	OTHER GENERATION	#N/A	1.54	1.60	1.88	#N/A	3.90	17.50
61	TOTAL (¢ / KWH)	1.93	1.64	1.53	1.60	(15.03)	(6.71)	4.58

Schedule CCE-1
Revised 11/12/99

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2000 - December 2000

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) ($)	624,443	268,960	117,797	(5,448)	311,532	(691,878)	(752,400)	(324,720)	(630,168)	13,154	(87,516)	114,804	(1,041,440)
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Projected Market Capacity Payments	305,177	305,177	305,177	312,902	312,902	2,108,102	3,269,702	3,269,702	1,580,102	418,502	418,502	418,502	13,024,449
4	Projected Transmission Revenue	(7,000)	(9,000)	(42,000)	(50,000)	(13,000)	(21,000)	(32,000)	(18,000)	(18,000)	(83,000)	(84,000)	(44,000)	(421,000)
5	Total Projected Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	984,822	627,339	443,176	319,656	673,636	1,457,426	2,547,504	2,989,184	994,136	410,858	309,188	551,508	12,308,433
6	Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271
7	Projected Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	950,183	605,274	427,588	308,413	649,942	1,406,164	2,457,901	2,884,046	959,169	396,407	298,313	532,110	11,875,510
8	Amount Included in Retail Base Rate Revenues ($)	(137,666)	(137,666)	(137,666)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(1,652,000)
9	*Jurisdictional Amount to be Recovered (Line 7 - Line 8)* ($)	1,087,849	742,940	565,254	446,080	787,609	1,543,831	2,595,568	3,021,713	1,096,836	534,074	435,980	669,776	13,527,510
10	True-Up ($)													(68,182)
11	Total Jurisdictional Amount to be Recovered (Line 9 + Line 10) ($)													13,459,328
12	Revenue Tax Multiplier													1.01597
13	Total Recoverable Capacity Payments/(Receipts) (Line 11 x Line 12) ($)													13,674,274

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,637,521.41	96.48271%
FERC	59,696.01	3.51729%
Total	1,697,217.42	100.00000%

* Based on 1997 Actual Data

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2000 - December 2000

1	Estimated over/(under)-recovery, January 1999 - December 1999 (Schedule CCE-1b-1, Line 17)	($12,942)
2	Final True-Up, October 1997 - September 1998 (Exhibit No.____(TAD-1), filed April 1, 1999	(95,729)
3	Final True-Up, October 1998 - December 1998 (Exhibit No.____(TAD-1), filed April 1, 1999	176,853
4	Total Over/(Under)-Recovery	$68,182
5	Jurisdictional KWH sales, January 2000 - December 2000	10,013,721,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0007)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 1999 - December 1999

	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1 IIC Payments/(Receipts) ($)	829,072	696,859	472,257	437,944	565,742	602,518	(628,894)	1,139,814	58,136	27,752	(11,780)	109,269	4,298,689
2 Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3 Projected Market Capacity Payments									674,991	398,379	398,379	390,962	1,862,711
4 Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	891,274	759,061	534,459	500,146	627,944	664,720	(566,692)	1,202,016	795,329	488,333	448,801	562,433	6,907,824
5 Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	
6 Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	859,925	732,363	515,660	482,555	605,857	641,340	(546,760)	1,159,738	767,355	471,157	433,015	542,651	6,664,856
7 Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,667)	(137,667)	(137,666)	(137,667)	(137,667)	(137,666)	(1,652,000)
8 Total Jurisdictional Recovery Amount (Line 6 - Line 7) ($)	997,592	870,030	653,328	620,222	743,525	779,007	(409,093)	1,297,405	905,021	608,824	570,682	680,317	8,316,860
9 Retail KWH Sales									876,848,000	702,438,000	659,165,000	791,003,000	
10 Purchased Power Capacity Cost Recovery Factor (¢/KWH)									0.102	0.102	0.102	0.102	
11 Capacity Cost Recovery Revenues (Line 9 x Line 10/100) ($)	767,136	622,643	646,079	723,608	813,135	955,600	1,077,304	1,122,427	894,385	716,487	672,348	806,823	9,817,975
12 Revenue Taxes (Line 11 x .01572) ($)	12,059	9,788	10,156	11,375	12,782	15,022	16,935	17,645	14,060	11,263	10,569	12,683	154,337
13 True-Up Provision ($)	(109,597)	(109,597)	(109,597)	(109,597)	(109,597)	(109,597)	(109,598)	(109,597)	(109,597)	(109,597)	(109,598)	(109,598)	(1,315,167)
14 Capacity Cost Recovery Revenues net of Revenue Taxes (Line 11 - Line 12 + Line 13) ($)	645,480	503,258	526,326	602,636	690,756	830,981	950,771	995,185	770,728	595,627	552,181	684,542	8,348,471
15 Over/(Under) Recovery (Line 14 - Line 8) ($)	(352,112)	(366,772)	(127,002)	(17,586)	(52,769)	51,974	1,359,864	(302,220)	(134,293)	(13,197)	(18,501)	4,225	31,611
16 Interest Provision ($)	(5,483)	(6,483)	(7,113)	(6,954)	(6,661)	(6,411)	(3,151)	(477)	(677)	(798)	(394)	49	(44,553)
17. Total Estimated True-Up for the Period January 1999 - December 1999 (Line 15 + Line 16) ($)													(12,942)

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2000 - December 2000

Rate Class	A Average 12 CP Load Factor at Meter	B Jan - Dec 00 Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F Jan - Dec 00 Projected KWH Sales at Generation Col B x Col E	G Projected Avg 12 CP KW at Generation Col C x Col D	H Percentage of KWH Sales at Generation Col F / Total Col F	I Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RST	57.217702%	4,669,455,000	931,604.71	1.1019333	1.0766175	5,027,216,968	1,026,566.25	47.18085%	56.09219%
GS, GST	57.820776%	263,808,000	52,083.47	1.1019255	1.0766135	284,019,254	57,392.10	2.66554%	3.13594%
GSD, GSDT	72.316857%	2,195,727,000	346,604.90	1.1016647	1.0764011	2,363,482,958	381,842.38	22.18148%	20.86409%
LP, LPT	85.738506%	1,088,382,000	144,910.99	1.0601470	1.0444167	1,136,724,337	153,626.95	10.66825%	8.39427%
PX, PXT, RTP, SBS	97.623712%	1,680,197,000	196,472.05	1.0313379	1.0235079	1,719,694,903	202,629.07	16.13947%	11.07177%
OS-I, OS-II	299.917227%	87,532,000	3,331.67	1.1020255	1.0766162	94,238,369	3,671.59	0.88443%	0.20062%
OS-III	98.962375%	23,970,000	2,764.99	1.1024447	1.0766529	25,807,370	3,048.25	0.24220%	0.16656%
OS-IV	34.482597%	3,739,000	1,237.80	1.1024447	1.0766529	4,025,605	1,364.61	0.03778%	0.07456%
TOTAL	67.948463%	10,012,810,000	1,679,010.58			10,655,209,764	1,830,141.20	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 1997 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2000 - December 2000

Rate Class	A Jan - Dec 00 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 00 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RST	47.18085%	56.09219%	496,279	7,080,184	7,576,463	4,669,455,000	0.162
GS, GST	2.66554%	3.13594%	28,038	395,831	423,869	263,808,000	0.161
GSD, GSDT	22.18148%	20.86409%	233,320	2,633,550	2,866,870	2,195,727,000	0.131
LP, LPT	10.66825%	8.39427%	112,216	1,059,559	1,171,775	1,088,382,000	0.108
PX, PXT, RTP, SBS	16.13947%	11.07177%	169,766	1,397,524	1,567,290	1,680,197,000	0.093
OS-I, OS-II	0.88443%	0.20062%	9,303	25,323	34,626	87,532,000	0.040
OS-III	0.24220%	0.16656%	2,548	21,024	23,572	23,970,000	0.098
OS-IV	0.03778%	0.07456%	397	9,411	9,808	3,739,000	0.262
TOTAL	100.00000%	100.00000%	$1,051,867	$12,622,406	$13,674,273	10,012,810,000	0.137

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 990001-EI

Before me the undersigned authority, personally appeared Terry A. Davis, who being first duly sworn, deposes, and says that she is the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Terry A. Davis
Staff Accountant

Sworn to and subscribed before me this 12th day of November, 1999.

Notary Public, State of Florida at Large

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31, 2002
Comm. No: CC 725969

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	Docket No. 990001-EI

Certificate of Service

I HEREBY CERTIFY that a true copy of the foregoing was furnished by hand delivery or the U. S. Mail this 15th day of November 1999 on the following:

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SCHEDULE E-1A

CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 1999 (Sch. E-1B, page 2, line 8)	($11,302,259)
2.	Final over/(under)-recovery APRIL - SEPTEMBER 1998 (EXHIBIT No.____(TAD-1), filed April 1, 1999	($2,694,132)
3.	Final over/(under)-recovery OCTOBER - DECEMBER 1998 (EXHIBIT No.____(TAD-1), filed April 1, 1999	243,932
4.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2000 - DECEMBER 2000 (Schedule E1, Line 28)	($13,752,459)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000	10,013,721,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1373

SCHEDULE E-1B
Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

				JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		14,351,953.22	9,860,077.35	13,191,125.11	14,863,512.47	17,803,592.11	19,370,034.96	$89,440,295.22
	2	Fuel Cost of Power Sold		(3,008,087.58)	(1,275,456.79)	(4,581,153.46)	(6,164,111.68)	(5,801,721.75)	(6,169,985.70)	($27,000,516.96)
	3	Fuel Cost of Purchased Power		1,281,132.92	1,888,655.37	809,394.67	4,183,039.81	772,463.85	2,969,131.87	11,903,818.49
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities		144,098.58	325,163.30	353,966.39	471,354.71	258,933.13	220,062.00	1,773,578.11
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation		164,962.27	128,390.94	153,585.56	143,239.28	143,105.29	136,738.10	870,021.44
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$12,934,059.41	$10,926,830.17	$9,926,918.27	$13,497,034.59	$13,176,372.63	$16,525,981.23	$76,987,196.30
B	1	Jurisdictional KWH Sales		739,104,445	602,521,261	645,839,727	711,513,543	796,267,435	910,695,185	4,405,941,596
	2	Non-Jurisdictional KWH Sales		24,226,819	22,364,388	23,203,899	24,870,728	27,675,927	30,778,442	153,120,203
	3	TOTAL SALES (Lines B1 + B2)		763,331,264	624,885,649	669,043,626	736,384,271	823,943,362	941,473,627	4,559,061,799
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.8262%	96.4210%	96.5318%	96.6226%	96.6410%	96.7308%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$12,059,017.95	$9,860,883.55	$10,521,228.60	$11,633,665.19	$13,027,358.60	$14,931,967.19	$72,034,121.08
	1a	Special Contract Recovery Cost		(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(10,144.83)	(60,868.98)
	2	True-Up Provision		(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(2,192,287.50)
	2a	Incentive Provision		(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(30,823.50)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$11,678,354.62	$9,480,220.22	$10,140,565.27	$11,253,001.86	$12,646,695.27	$14,551,303.86	$69,750,141.10
	4	Fuel & Net Power Transactions (Line A6)		$12,934,059.41	$10,926,830.17	$9,926,918.27	$13,497,034.59	$13,176,372.63	$16,525,981.23	$76,987,196.30
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		12,541,091.21	10,550,508.98	9,596,048.58	13,059,443.40	12,751,605.56	16,008,093.85	$74,506,791.58
	6	Over/(Under) Recovery (Line C3-C5)		(862,736.59)	(1,070,288.76)	544,516.69	(1,806,441.54)	(104,910.29)	(1,456,789.99)	($4,756,650.48)
	7	Interest Provision	(2)	(28,659.66)	(31,045.81)	(30,979.84)	(32,015.39)	(34,422.44)	(37,168.55)	($194,291.69)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 1999 - DECEMBER 1999**								($4,950,942.17)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

				JULY ACTUAL	AUGUST ACTUAL	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		22,219,817.08	22,978,684.23	17,129,407.00	16,856,077.00	14,847,061.00	13,824,090.00	$197,295,431.53
	2	Fuel Cost of Power Sold		(10,287,872.88)	(15,896,257.40)	(3,862,800.00)	(5,763,800.00)	(4,192,800.00)	(2,359,400.00)	($69,363,447.24)
	3	Fuel Cost of Purchased Power		7,031,703.54	12,568,967.75	891,000.00	251,000.00	110,000.00	1,289,000.00	$34,045,489.78
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		873,664.00	966,622.00	19,378.00	2,422.00	0.00	0.00	$3,635,664.11
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		136,738.00	129,653.98	168,375.00	173,971.00	168,375.00	173,971.00	$1,821,105.42
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A5)		$19,974,049.74	$20,747,670.56	$14,345,360.00	$11,519,670.00	$10,932,636.00	$12,927,661.00	$167,434,243.60
B	1	Jurisdictional KWH Sales		1,020,841,104	1,058,379,070	876,848,000	702,438,000	659,165,000	791,003,000	9,514,615,770
	2	Non-Jurisdictional KWH Sales		34,945,824	38,187,471	31,340,000	27,518,000	26,107,000	29,043,000	340,261,498
	3	TOTAL SALES (Lines B1 + B2)		1,055,786,928	1,096,566,541	908,188,000	729,956,000	685,272,000	820,046,000	9,854,877,268
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.6901%	96.5175%	96.5492%	96.2302%	96.1903%	96.4584%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$16,742,454.02	$17,367,278.57	$14,344,356.43	$11,491,183.24	$10,783,280.24	$12,940,018.08	$155,702,691.66
	1a	Special Contract Recovery Cost		(10,144.83)	(10,144.83)	(10,144.84)	(10,144.84)	(10,144.84)	(10,144.84)	($121,738.00)
	2	True-Up Provision		(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	(365,381.25)	($4,384,575.00)
	2a	Incentive Provision		(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	(5,137.25)	($61,647.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$16,361,790.69	$16,986,615.24	$13,963,693.09	$11,110,519.90	$10,402,616.90	$12,559,354.74	$151,134,731.66
	4	Fuel & Net Power Transactions (Line A6)		$19,974,049.74	$20,747,670.56	$14,345,360.00	$11,519,670.00	$10,932,636.00	$12,927,661.00	$167,434,243.60
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A6 x Line B4 x 1.0014)		19,339,966.77	20,053,168.12	13,869,720.78	11,100,921.04	10,530,857.96	12,487,272.70	$161,888,698.95
	6	Over/(Under) Recovery (Line C3-C5)		(2,978,176.08)	(3,066,552.88)	93,972.31	9,598.86	(128,241.06)	72,082.04	($10,753,967.29)
	7	Interest Provision	(2)	(46,095.38)	(59,063.82)	(64,187.27)	(62,654.63)	(61,597.76)	(60,400.65)	($548,291.20)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 1999 - DECEMBER 1999**								($11,302,258.49)

Note 1: Estimated Revenues based on the Jan through Dec Fuel Factor excluding revenue taxes of 1.6359 ¢/KWH
Note 2: Interest Calculated for September through December at August's rate of 0.4342

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 1999 - DECEMBER 1999

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ACTUAL	EST.	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	197,295,432	190,141,031	7,154,401	3.76	12,636,967,000	12,440,570,000	196,397,000	1.58	1.5613	1.5284	0.0329	2.15
2	Nuclear Fuel Disposal Costs	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,821,105	1,981,161	(160,056)	(8.08)	113,441,000	123,900,000	(10,459,000)	(8.44)	1.6053	1.599	0.0063	0.39
5	TOTAL COST OF GENERATED POWER	199,116,537	192,122,192	6,994,345	3.64	12,750,408,000	12,564,470,000	185,938,000	1.48	1.5616	1.5291	0.0325	2.13
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	7,144,399	0	7,144,399	#N/A	168,529,072	0	168,529,072	#N/A	4.2393	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	26,901,091	10,269,000	16,632,091	100.00	865,855,793	531,400,000	334,455,793	62.94	3.1069	1.9324	1.1745	60.78
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	3,635,664	194,260	3,441,404	1,771.55	109,740,265	8,970,000	100,770,265	1,123.41	3.313	2.1657	1.1473	52.98
12	TOTAL COST OF PURCHASED POWER	37,681,154	10,463,260	27,217,894	260.13	1,144,125,130	540,370,000	603,755,130	111.73	3.2934	1.9363	1.3571	70.09
13	Total Available KWH (Lines 4 + Line 12)	236,797,691	202,585,452	34,212,239	16.89	13,894,533,130	13,104,840,000	789,693,130	6.03				
14	Fuel Cost of Economy Sales (A6)	(1,643,879)	(1,337,000)	(306,879)	(22.95)	(75,326,814)	(50,260,000)	(25,066,814)	(49.87)	(2.1823)	(2.6602)	0.4779	17.96
15	*Gain on Economy Sales (A6)*	(680,827)	(141,600)	(539,227)	(380.81)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(14,326,927)	(12,794,000)	(1,532,927)	(11.98)	(794,513,045)	(685,670,000)	(108,843,045)	(15.87)	(1.8032)	(1.8659)	0.0627	3.36
17	Fuel Cost of Other Power Sales (A6)	(52,711,815)	(29,490,000)	(23,221,815)	(78.74)	(2,533,054,867)	(1,716,879,000)	(816,175,867)	(47.54)	(2.0810)	(1.7177)	(0.3633)	(21.15)
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(69,363,448)	(43,762,600)	(25,600,848)	(58.50)	(3,402,894,726)	(2,452,809,000)	(950,085,726)	(38.73)	(2.0384)	(1.7842)	(0.2542)	(14.25)
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	167,434,243	158,822,852	8,611,391	5.42	10,491,638,404	10,652,031,000	(160,392,596)	(1.51)	1.5959	1.491	0.1049	7.04
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	337,043	305,402	31,641	10.36	21,119,298	20,483,000	636,298	3.11	1.5959	1.491	0.1049	7.04
23	T & D Losses *	9,825,028	9,229,022	596,006	6.46	615,641,838	618,982,000	(3,340,162)	(0.54)	1.5959	1.491	0.1049	7.04
24	TERRITORIAL (SYSTEM) SALES	167,434,243	158,822,852	8,611,391	5.42	9,854,877,268	10,012,566,000	(157,688,732)	(1.57)	1.699	1.5862	0.1128	7.11
25	Wholesale Sales	5,771,871	5,576,080	195,791	3.51	340,261,498	351,537,000	(11,275,502)	(3.21)	1.6963	1.5862	0.1101	6.94
26	Jurisdictional Sales	161,662,372	153,246,772	8,415,600	5.49	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.6991	1.5862	0.1129	7.12
26a	Jurisdictional Loss Multiplier	1.0014	1.0014										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0014)	161,888,699	153,461,317	8,427,382	5.49	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.7015	1.5885	0.1130	7.11
28	TRUE-UP **	4,384,575	4,384,575	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0461	0.0454	0.0007	1.54
29	TOTAL JURISDICTIONAL FUEL COST	166,273,274	157,845,892	8,427,382	5.34	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	1.7476	1.6339	0.1137	6.96
30	Revenue Tax Factor									1.01609	1.01609		
31	Fuel Factor Adjusted for Revenue Taxes									1.7757	1.6602	0.1155	6.96
32	GPIF Reward / (Penalty) **	62,632	62,632	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0007	0.0006	0.0001	16.67
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									1.7764	1.6608	0.1156	6.96
33a	*Special Contract Recovery Cost (Incl. Revenue Taxes)* **	123,682	123,682	0	0.00	9,514,615,770	9,661,029,000	(146,413,230)	(1.52)	0.0013	0.0013	0.0000	0.00
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									1.778	1.662	0.116	6.98

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts Included in the Estimated/Actual Column represent 8 months actual and 4 month estimates. Amounts Included in the Estimated Original Column represent amounts projected in previous fuel adjustment period.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	(36,679)
	B. True-Up (Over)/Under Recovered	$	13,752,459
2.	TOTAL SALES (KWH)		10,013,721,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		(0.0004)
	B. True-Up Factor		0.1373

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		NET ENERGY FOR LOAD %
	On-Peak	34.68
	Off-Peak	65.32
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	1.7800	2.2238	1.5443
Jurisdictional Loss Factor	1.0014	1.0014	1.0014
Jurisdictional Fuel Factor	1.7825	2.2269	1.5465
GPIF	-0.0004	-0.0004	-0.0004
True-Up	0.1373	0.1373	0.1373
TOTAL	1.9194	2.3638	1.6834
Revenue Tax Factor	1.01597	1.01597	1.01597
Recovery Factor	1.9501	2.4015	1.7103
Recovery Factor Rounded to the Nearest .001 ¢/KWH	1.950	2.402	1.710

HOURS:	ON-PEAK	24.93%
	OFF-PEAK	75.07%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, OSIV, SBS (1)	1.950	1.01228	1.974
B	LP, SBS (2)	1.950	0.98106	1.913
C	PX, PXT, RTP, SBS (3)	1.950	0.96230	1.876
D	OSI, OSII	1.950	1.01228	1.906 *

		TOU
A	On-Peak	2.431
	Off-Peak	1.731
B	On-Peak	2.356
	Off-Peak	1.678
C	On-Peak	2.311
	Off-Peak	1.646
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	2.402 ¢ / KWH	x	0.2493	=	0.599 ¢ / KWH
	Off-Peak	1.710 ¢ / KWH	x	0.7507	=	1.284 ¢ / KWH
						1.883 ¢ / KWH
			Line Loss Multiplier		x	1.01228
						1.906 ¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW
(3) Includes SBS customers with a Contract Demand over 7,499 KW

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	14,991,952	11,977,253	11,448,315	14,742,838	16,730,497	19,610,417	21,027,459	21,823,642	17,513,543	13,563,278	15,268,803	16,309,140	195,007,137
1a	Other Generation	163,212	152,706	163,212	157,959	163,212	157,959	163,212	163,212	157,959	163,212	157,959	163,212	1,927,026
2	Fuel Cost of Power Sold	(2,294,000)	(1,911,000)	(2,780,000)	(3,817,000)	(3,604,000)	(4,092,000)	(5,568,000)	(6,012,000)	(3,708,000)	(2,752,000)	(3,861,000)	(3,493,000)	(43,892,000)
3	Fuel Cost of Purchased Power	1,675,000	1,229,000	4,235,000	1,130,000	1,146,000	3,456,000	6,388,000	6,078,000	2,381,000	1,494,000	582,000	1,620,000	31,414,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	4,319	664	3,654	6,042	13,247	18,824	67,396	78,551	12,317	3,718	0	0	208,732
4	Energy Cost of Economy Purchases													0
5	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	14,540,483	11,448,623	13,070,181	12,219,839	14,448,956	19,151,200	22,078,067	22,131,405	16,356,819	12,472,208	12,147,762	14,599,352	184,664,895
6	System KWH Sold	857,362,000	708,547,000	753,891,000	750,400,000	880,287,000	1,025,331,000	1,066,097,000	1,071,696,000	936,129,000	756,228,000	715,783,000	852,594,000	10,374,345,000
6a	*Jurisdictional % of Total Sales*	96.4705	96.1668	96.4674	96.4280	96.5013	96.8142	96.5658	96.6864	96.6523	96.2556	96.3081	96.7044	96.5239
7	Cost per KWH Sold (¢/KWH)	1.6960	1.6158	1.7337	1.6284	1.6414	1.8678	2.0709	2.0651	1.7473	1.6493	1.6971	1.7123	1.7800
7a	Jurisdictional Loss Multiplier	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014	1.0014
7b	Jurisdictional Cost (¢/KWH)	1.6984	1.6181	1.7361	1.6307	1.6437	1.8704	2.0738	2.0680	1.7497	1.6516	1.6995	1.7147	1.7825
8	GPIF (¢ / KWH) *	(0.0004)	(0.0004)	(0.0004)	(0.0004)	(0.0004)	(0.0003)	(0.0003)	(0.0003)	(0.0003)	(0.0004)	(0.0004)	(0.0004)	(0.0004)
9	True-Up (¢/KWH) *	0.1386	0.1682	0.1576	0.1584	0.1349	0.1155	0.1113	0.1106	0.1267	0.1574	0.1662	0.1390	0.1373
10	TOTAL	1.8366	1.7859	1.8933	1.7887	1.7782	1.9856	2.1848	2.1783	1.8761	1.8086	1.8653	1.8533	1.9194
11	Revenue Tax Factor	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597	1.01597
12	Recovery Factor Adjusted for Taxes	1.8659	1.8144	1.9235	1.8173	1.8066	2.0173	2.2197	2.2131	1.9061	1.8375	1.8951	1.8829	1.9501
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	1.866	1.814	1.924	1.817	1.807	2.017	2.220	2.213	1.906	1.838	1.895	1.883	1.950

* CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
2	LIGHTER OIL	26,611	26,925	22,018	26,884	27,388	27,506	28,096	28,162	28,221	23,593	28,313	28,352	322,069
3	COAL excluding Scherer	13,559,495	11,275,604	9,115,874	12,587,322	14,699,319	17,133,249	17,858,376	18,573,039	15,032,032	11,431,118	13,273,673	14,421,084	168,960,185
3a	COAL at Scherer	1,374,365	649,838	2,292,463	2,111,428	1,981,436	2,148,972	2,252,376	2,278,698	2,029,017	2,094,343	1,949,136	1,841,512	23,003,584
4	GAS	2,840	6,224	8,543	1,123	4,999	283,882	858,563	911,729	405,901	0	0	58	2,483,862
4a	GAS (B.L.)	18,134	17,681	8,030	16,081	16,081	16,081	17,221	17,221	16,081	14,224	17,681	18,134	192,650
6	OTHER - C.T.	10,507	981	1,387	0	1,274	727	12,827	14,793	2,291	0	0	0	44,787
6a	OTHER GENERATION	163,212	152,706	163,212	157,959	163,212	157,959	163,212	163,212	157,959	163,212	157,959	163,212	1,927,026
7	TOTAL ($)	15,155,164	12,129,959	11,611,527	14,900,797	16,893,709	19,768,376	21,190,671	21,986,854	17,671,502	13,726,490	15,426,762	16,472,352	196,934,163
	SYSTEM NET GEN. (MWH)													
8	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
9	LIGHTER OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
10	COAL	970,730	780,220	714,420	939,900	1,052,990	1,219,570	1,259,290	1,305,120	1,061,890	848,590	952,150	1,008,340	12,113,210
11	GAS	70	150	200	30	130	6,500	18,750	20,140	9,050	0	0	0	55,020
13	OTHER - C.T.	230	20	30	0	30	20	270	310	50	0	0	0	960
13a	OTHER GENERATION	8,700	8,140	8,700	8,420	8,700	8,420	8,700	8,700	8,420	8,700	8,420	8,700	102,720
14	TOTAL (MWH)	979,730	788,530	723,350	948,350	1,061,850	1,234,510	1,287,010	1,334,270	1,079,410	857,290	960,570	1,017,040	12,271,910
	UNITS OF FUEL BURNED													
15	HEAVY OIL (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
16	LIGHTER OIL (BBL)	1,344	1,342	1,082	1,321	1,338	1,338	1,335	1,335	1,334	1,114	1,334	1,334	15,551
17	COAL excl. Scherer (TON)	410,805	344,116	264,523	372,935	427,761	489,105	504,733	520,479	419,704	318,892	369,810	400,934	4,843,797
18	GAS-all (MCF)	7,222	8,442	5,853	6,680	8,185	116,468	317,543	336,820	163,845	5,523	6,244	6,264	989,089
20	OTHER - C.T. (BBL)	539	50	71	0	65	37	652	746	115	0	0	0	2,275
	BTU'S BURNED (MMBTU)													
21	HEAVY OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
22	LIGHTER OIL	0	0	0	0	0	0	0	0	0	0	0	0	0
23	COAL + GAS B.L. + OIL B.L.	10,032,973	8,031,773	7,409,674	9,653,041	10,942,597	12,569,224	13,036,498	13,466,844	11,017,973	8,792,229	9,825,798	10,481,757	125,260,381
24	GAS-Generation	1,007	2,264	3,108	449	1,999	113,531	320,638	340,493	162,329	0	0	21	945,839
26	OTHER - C.T.	3,141	293	414	0	380	217	3,802	4,356	674	0	0	0	13,277
27	TOTAL (MMBTU)	10,037,121	8,034,330	7,413,196	9,653,490	10,944,976	12,682,972	13,360,938	13,811,693	11,180,976	8,792,229	9,825,798	10,481,778	126,219,497

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
28	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	LIGHTER OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	COAL	99.08	98.95	98.77	99.11	99.17	98.79	97.84	97.82	98.38	98.99	99.12	99.14	98.70
31	GAS-Generation	0.01	0.02	0.03	0.00	0.01	0.53	1.46	1.51	0.84	0.00	0.00	0.00	0.45
33	OTHER - C.T.	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.00	0.01
33a	OTHER GENERATION	0.89	1.03	1.20	0.89	0.82	0.68	0.68	0.65	0.78	1.01	0.88	0.86	0.84
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
35	HEAVY OIL ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
36	LIGHTER OIL ($/BBL)	19.80	20.06	20.35	20.35	20.47	20.56	21.05	21.10	21.16	21.18	21.22	21.25	20.71
37	COAL ($/TON)	33.01	32.77	34.46	33.75	34.36	35.03	35.38	35.68	35.82	35.85	35.89	35.97	34.88
38	GAS + B.L. ($/MCF)	2.90	2.83	2.83	2.58	2.58	2.58	2.76	2.76	2.58	2.58	2.83	2.90	2.71
40	OTHER - C.T.	19.49	19.62	19.54	#N/A	19.60	19.65	19.67	19.83	19.92	#N/A	#N/A	#N/A	19.69
	FUEL COST $ / MMBTU													
41	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.49	1.49	1.54	1.52	1.53	1.54	1.54	1.55	1.55	1.54	1.55	1.55	1.53
44	GAS-Generation	2.82	2.75	2.75	2.50	2.50	2.50	2.68	2.68	2.50	#N/A	#N/A	2.76	2.63
46	OTHER - C.T.	3.35	3.35	3.35	#N/A	3.35	3.35	3.37	3.40	3.40	#N/A	#N/A	#N/A	3.37
47	TOTAL ($/MMBTU)	1.51	1.51	1.57	1.54	1.54	1.56	1.59	1.59	1.58	1.56	1.57	1.57	1.56
	BTU BURNED BTU / KWH													
48	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,335	10,294	10,372	10,270	10,392	10,306	10,352	10,318	10,376	10,361	10,320	10,395	10,341
51	GAS-Generation	14,386	15,093	15,540	14,967	15,377	17,466	17,101	16,906	17,937	#N/A	#N/A	#N/A	17,191
53	OTHER - C.T.	13,657	14,650	13,800	#N/A	12,667	10,850	14,081	14,052	13,480	#N/A	#N/A	#N/A	13,830
54	TOTAL (BTU/KWH)	10,245	10,189	10,248	10,179	10,307	10,274	10,381	10,351	10,358	10,256	10,229	10,306	10,285
	FUEL COST CENTS / KWH													
55	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.54	1.53	1.60	1.57	1.59	1.58	1.60	1.60	1.61	1.60	1.60	1.62	1.59
58	GAS-Generation	4.06	4.15	4.27	3.74	3.85	4.37	4.58	4.53	4.49	#N/A	#N/A	#N/A	4.51
60	OTHER - C.T.	4.57	4.91	4.62	#N/A	4.25	3.64	4.75	4.77	4.58	#N/A	#N/A	#N/A	4.67
60a	OTHER GENERATION	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
61	TOTAL (¢/KWH)	1.55	1.54	1.61	1.57	1.59	1.60	1.65	1.65	1.64	1.60	1.61	1.62	1.60

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	20	0.1	100.0	0.1	15,700	Gas - G	305	1,030	314	886	4.43	2.90
2	1							Oil - G						
3	Crist 2	24.0	20	0.1	100.0	0.1	12,400	Gas - G	241	1,030	248	699	3.50	2.90
4	2							Oil - G						
5	Crist 3	35.0	30	0.1	100.0	0.1	14,833	Gas - G	432	1,030	445	1,255	4.18	2.91
6	3							Oil - G						
7	Crist 4	78.0	43,070	74.2	95.2	78.0	10,191	Coal	18,351	11,959	438,919	647,969	1.50	35.31
8	4							Gas - G						
9	Crist 5	80.0	40,090	67.4	95.7	70.4	10,473	Coal	17,555	11,959	419,880	619,884	1.55	35.31
10	5							Gas - G						
11	Crist 6	302.0	75,590	33.6	43.7	77.0	10,667	Coal	33,711	11,959	806,346	1,190,351	1.57	35.31
12	6							Gas - G						
13	Crist 7	465.0	287,810	83.2	91.9	90.5	10,237	Coal	123,186	11,959	2,946,414	4,349,670	1.51	35.31
14	7							Gas - G						
15	Scherer 3 (2)	214.1	72,640	45.6	65.6	69.5	10,245	Coal			744,199	1,374,365	1.89	#N/A
16	Scholz 1	46.0	9,670	28.3	92.7	30.5	13,091	Coal	4,996	12,669	126,589	207,222	2.14	41.48
17	Scholz 2	46.0	10,100	29.5	96.9	30.5	13,120	Coal	5,230	12,669	132,511	216,952	2.15	41.48
18	Smith 1	162.0	77,730	64.5	98.1	65.7	10,456	Coal	33,933	11,976	812,763	1,161,175	1.49	34.22
19	Smith 2	192.6	105,810	73.8	96.9	76.2	10,118	Coal	44,693	11,976	1,070,564	1,529,407	1.45	34.22
20	Smith A (CT)	31.6	230	1.0	99.9	1.0	13,657	Oil - G	539	138,653	3,141	10,507	4.57	19.49
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	239.0	150,840	84.8	92.9	91.3	10,245	Coal	79,186	9,758	1,545,397	2,229,884	1.48	28.16
23	Daniel 2 (1)	239.0	97,380	54.8	57.7	94.9	10,013	Coal	49,964	9,758	975,097	1,406,981	1.44	28.16
24	Gas,BL							Gas	6,244	1,030	6,432	18,134	#N/A	2.90
25	Ltr. Oil							Oil	1,344	139,281	7,862	26,611	#N/A	19.80
26		2,178.3	979,730	60.5	80.7	74.9	10,245				10,037,121	15,155,164	1.55	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	50	0.3	48.3	0.6	15,020	Gas - G	729	1,030	751	2,065	4.13	2.83
2	1							Oil - G						
3	Crist 2	24.0	30	0.2	48.3	0.4	15,133	Gas - G	441	1,030	454	1,248	4.16	2.83
4	2							Oil - G						
5	Crist 3	35.0	70	0.3	48.3	0.6	15,129	Gas - G	1,028	1,030	1,059	2,911	4.16	2.83
6	3							Oil - G						
7	Crist 4	78.0	42,240	77.8	95.1	81.8	10,137	Coal	17,877	11,976	428,190	632,141	1.50	35.36
8	4							Gas - G						
9	Crist 5	80.0	39,920	71.7	95.7	74.9	10,394	Coal	17,324	11,976	414,944	612,573	1.53	35.36
10	5							Gas - G						
11	Crist 6	302.0	16,740	8.0	9.8	81.3	10,657	Coal	7,448	11,976	178,394	263,364	1.57	35.36
12	6							Gas - G						
13	Crist 7	465.0	236,500	73.1	78.6	93.0	10,229	Coal	101,004	11,976	2,419,219	3,571,492	1.51	35.36
14	7							Gas - G						
15	Scherer 3 (2)	214.1	33,710	22.6	30.0	75.4	10,204	Coal			343,985	649,838	1.93	#N/A
16	Scholz 1	46.0	6,520	20.4	63.9	31.9	13,030	Coal	3,353	12,669	84,958	139,098	2.13	41.48
17	Scholz 2	46.0	9,960	31.1	96.8	32.1	13,045	Coal	5,128	12,669	129,926	212,694	2.14	41.48
18	Smith 1	162.0	36,610	32.5	44.0	73.8	10,342	Coal	15,783	11,994	378,603	549,733	1.50	34.83
19	Smith 2	192.6	105,540	78.7	97.0	81.2	10,081	Coal	44,356	11,994	1,063,968	1,544,908	1.46	34.83
20	Smith A (CT)	31.6	20	0.1	100.0	0.1	14,650	Oil - G	50	138,664	293	981	4.91	19.50
21	Other Generation		8,140									152,706	1.88	#N/A
22	Daniel 1 (1)	239.0	124,200	74.7	79.7	93.7	10,311	Coal	65,562	9,767	1,280,624	1,864,575	1.50	28.44
23	Daniel 2 (1)	239.0	128,280	77.1	80.7	95.6	10,093	Coal	66,281	9,767	1,294,669	1,885,026	1.47	28.44
24	Gas,BL							Gas	6,244	1,030	6,431	17,681	#N/A	2.83
25	Ltr. Oil							Oil	1,342	139,521	7,862	26,925	#N/A	20.07
26		2,178.3	788,530	52.0	64.1	81.1	10,189				8,034,330	12,129,959	1.54	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	50	0.3	100.0	0.3	17,320	Gas - G	841	1,030	866	2,380	4.76	2.83
2	1							Oil - G						
3	Crist 2	24.0	40	0.2	100.0	0.2	16,300	Gas - G	633	1,030	652	1,792	4.48	2.83
4	2							Oil - G						
5	Crist 3	35.0	110	0.4	100.0	0.4	14,455	Gas - G	1,543	1,030	1,590	4,371	3.97	2.83
6	3							Oil - G						
7	Crist 4	78.0	46,540	80.2	95.2	84.2	10,104	Coal	19,619	11,984	470,228	693,911	1.49	35.37
8	4							Gas - G						
9	Crist 5	80.0	45,100	75.8	95.7	79.2	10,335	Coal	19,448	11,984	466,130	687,885	1.53	35.37
10	5							Gas - G						
11	Crist 6	302.0	170,190	75.7	90.2	84.0	10,636	Coal	75,528	11,984	1,810,160	2,671,429	1.57	35.37
12	6							Gas - G						
13	Crist 7	465.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,984	0	0	#N/A	#N/A
14	7							Gas - G						
15	Scherer 3 (2)	214.1	122,610	77.0	96.9	79.4	10,181	Coal			1,248,273	2,292,463	1.87	#N/A
16	Scholz 1	46.0	14,180	41.4	95.0	43.6	12,274	Coal	6,944	12,532	174,044	293,296	2.07	42.24
17	Scholz 2	46.0	14,580	42.6	97.8	43.6	12,316	Coal	7,164	12,532	179,562	302,626	2.08	42.24
18	Smith 1	162.0	92,820	77.0	98.1	78.5	10,287	Coal	39,772	12,004	954,846	1,401,182	1.51	35.23
19	Smith 2	192.6	119,780	83.6	96.9	86.3	10,049	Coal	50,132	12,004	1,203,639	1,766,136	1.47	35.23
20	Smith A (CT)	31.6	30	0.1	100.0	0.1	13,800	Oil - G	71	138,680	414	1,387	4.62	19.52
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	239.0	0	0.0	0.0	#N/A	#N/A	Coal	0	9,730	0	0	#N/A	#N/A
23	Daniel 2 (1)	239.0	88,620	49.8	51.6	96.6	10,083	Coal	45,916	9,730	893,524	1,299,409	1.47	28.30
24	Gas,BL							Gas	2,836	1,030	2,921	8,030	#N/A	2.83
25	Ltr. Oil							Oil	1,082	139,691	6,347	22,018	#N/A	20.35
26		2,178.3	723,350	44.6	59.8	74.6	10,248				7,413,196	11,611,527	1.61	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	10	0.1	100.0	0.1	18,400	Gas - G	179	1,030	184	460	4.60	2.57
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	20	0.1	100.0	0.1	13,250	Gas - G	257	1,030	265	663	3.32	2.58
6	3							Oil - G						
7	Crist 4	78.0	43,910	78.2	95.1	82.2	10,137	Coal	18,561	11,991	445,130	656,859	1.50	35.39
8	4							Gas - G						
9	Crist 5	80.0	42,700	74.1	95.7	77.5	10,360	Coal	18,446	11,991	442,372	652,805	1.53	35.39
10	5							Gas - G						
11	Crist 6	302.0	158,340	72.8	90.3	80.6	10,465	Coal	69,095	11,991	1,656,974	2,445,282	1.54	35.39
12	6							Gas - G						
13	Crist 7	465.0	143,030	42.7	45.9	93.1	10,223	Coal	60,972	11,991	1,462,169	2,157,803	1.51	35.39
14	7							Gas - G						
15	Scherer 3 (2)	214.1	114,370	74.2	96.9	76.6	10,201	Coal			1,166,701	2,111,428	1.85	#N/A
16	Scholz 1	46.0	9,580	28.9	92.8	31.2	13,054	Coal	5,031	12,428	125,062	215,427	2.25	42.82
17	Scholz 2	46.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	12,428	0	0	#N/A	#N/A
18	Smith 1	162.0	78,510	67.3	87.8	76.7	10,203	Coal	33,345	12,011	801,014	1,183,088	1.51	35.48
19	Smith 2	192.6	104,130	75.1	90.4	83.1	10,067	Coal	43,637	12,011	1,048,279	1,548,233	1.49	35.48
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	103,390	56.3	64.8	86.9	10,270	Coal	52,789	10,057	1,061,831	1,588,946	1.54	30.10
23	Daniel 2 (1)	255.0	141,940	77.3	87.3	88.6	10,070	Coal	71,059	10,057	1,429,325	2,138,879	1.51	30.10
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,321	139,779	7,753	26,884	#N/A	20.36
26		2,210.3	948,350	59.6	77.2	77.2	10,179				9,653,490	14,900,797	1.57	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	40	0.2	100.0	0.2	15,850	Gas - G	616	1,030	634	1,585	3.96	2.57
2	1							Oil - G						
3	Crist 2	24.0	30	0.2	100.0	0.2	16,867	Gas - G	491	1,030	506	1,265	4.22	2.58
4	2							Oil - G						
5	Crist 3	35.0	60	0.2	100.0	0.2	14,317	Gas - G	834	1,030	859	2,149	3.58	2.58
6	3							Oil - G						
7	Crist 4	78.0	43,630	75.2	95.2	79.0	10,179	Coal	18,509	11,997	444,105	655,403	1.50	35.41
8	4							Gas - G						
9	Crist 5	80.0	41,930	70.4	95.7	73.6	10,427	Coal	18,221	11,997	437,195	645,207	1.54	35.41
10	5							Gas - G						
11	Crist 6	302.0	165,050	73.5	96.8	75.9	10,563	Coal	72,661	11,997	1,743,464	2,572,914	1.56	35.41
12	6							Gas - G						
13	Crist 7	465.0	283,920	82.1	91.9	89.3	10,377	Coal	122,785	11,997	2,946,183	4,347,828	1.53	35.41
14	7							Gas - G						
15	Scherer 3 (2)	214.1	107,510	67.5	96.9	69.7	10,250	Coal			1,101,970	1,981,436	1.84	#N/A
16	Scholz 1	46.0	11,660	34.1	95.2	35.8	12,400	Coal	5,855	12,348	144,582	253,299	2.17	43.26
17	Scholz 2	46.0	910	2.7	9.4	28.3	12,565	Coal	463	12,348	11,434	20,018	2.20	43.24
18	Smith 1	162.0	80,190	66.5	98.1	67.8	10,287	Coal	34,330	12,014	824,909	1,221,799	1.52	35.59
19	Smith 2	192.6	51,780	36.1	46.4	77.9	10,255	Coal	22,100	12,014	531,019	786,545	1.52	35.59
20	Smith A (CT)	31.6	30	0.1	100.0	0.1	12,667	Oil - G	65	138,695	380	1,274	4.25	19.53
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	129,640	68.3	92.9	73.6	10,418	Coal	65,395	10,326	1,350,589	2,065,828	1.59	31.59
23	Daniel 2 (1)	255.0	136,770	72.1	94.1	76.6	10,184	Coal	67,442	10,326	1,392,854	2,130,478	1.56	31.59
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,338	139,861	7,862	27,388	#N/A	20.46
26		2,210.3	1,061,850	64.6	88.9	72.6	10,307				10,944,976	16,893,709	1.59	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	1,830	10.6	99.0	10.7	18,260	Gas - G	32,443	1,030	33,416	83,556	4.57	2.58
2	1							Oil - G						
3	Crist 2	24.0	1,230	7.1	99.0	7.2	19,333	Gas - G	23,086	1,030	23,779	59,459	4.83	2.58
4	2							Oil - G						
5	Crist 3	35.0	3,440	13.7	99.0	13.8	16,377	Gas - G	54,695	1,030	56,336	140,867	4.09	2.58
6	3							Oil - G						
7	Crist 4	78.0	46,490	82.8	97.4	85.0	10,093	Coal	19,549	12,001	469,215	692,830	1.49	35.44
8	4							Gas - G						
9	Crist 5	80.0	45,230	78.5	97.6	80.5	10,318	Coal	19,443	12,001	466,671	689,066	1.52	35.44
10	5							Gas - G						
11	Crist 6	302.0	176,160	81.0	96.8	83.7	10,635	Coal	78,057	12,001	1,873,524	2,766,353	1.57	35.44
12	6							Gas - G						
13	Crist 7	465.0	302,170	90.3	91.9	98.2	10,198	Coal	128,386	12,001	3,081,395	4,549,967	1.51	35.44
14	7							Gas - G						
15	Scherer 3 (2)	214.1	118,600	76.9	97.1	79.2	10,183	Coal			1,207,704	2,148,972	1.81	#N/A
16	Scholz 1	46.0	16,950	51.2	93.9	54.5	12,401	Coal	8,566	12,269	210,200	374,344	2.21	43.70
17	Scholz 2	46.0	16,780	50.7	96.0	52.8	12,458	Coal	8,519	12,269	209,046	372,271	2.22	43.70
18	Smith 1	162.0	89,520	76.7	98.2	78.2	10,292	Coal	38,333	12,017	921,325	1,369,245	1.53	35.72
19	Smith 2	192.6	116,100	83.7	96.9	86.4	10,147	Coal	49,014	12,017	1,178,046	1,750,790	1.51	35.72
20	Smith A (CT)	31.6	20	0.1	100.0	0.1	10,850	Oil - G	37	138,703	217	727	3.64	19.52
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	142,210	77.5	92.9	83.4	10,127	Coal	68,260	10,550	1,440,228	2,239,609	1.57	32.81
23	Daniel 2 (1)	255.0	149,360	81.4	94.0	86.5	10,027	Coal	70,978	10,550	1,497,577	2,328,774	1.56	32.81
24	Gas,BL							Gas	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,338	139,931	7,862	27,506	#N/A	20.56
26		2,210.3	1,234,510	77.6	95.2	81.5	10,274				12,682,972	19,768,376	1.60	

Notes:
(1) *Represents Gulf's 50% Ownership*
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	5,250	29.4	97.4	30.2	17,873	Gas - G	91,100	1,030	93,833	251,254	4.79	2.76
2	1							Oil - G						
3	Crist 2	24.0	3,720	20.8	97.4	21.4	18,532	Gas - G	66,930	1,030	68,938	184,593	4.96	2.76
4	2							Oil - G						
5	Crist 3	35.0	9,780	37.6	97.4	38.6	16,142	Gas - G	153,269	1,030	157,867	422,716	4.32	2.76
6	3							Oil - G						
7	Crist 4	78.0	47,990	82.7	97.3	85.0	10,098	Coal	20,186	12,003	484,585	715,785	1.49	35.46
8	4							Gas - G						
9	Crist 5	80.0	47,420	79.7	97.7	81.5	10,306	Coal	20,357	12,003	488,690	721,859	1.52	35.46
10	5							Gas - G						
11	Crist 6	302.0	181,350	80.7	96.8	83.4	10,637	Coal	80,357	12,003	1,929,050	2,849,474	1.57	35.46
12	6							Gas - G						
13	Crist 7	465.0	309,690	89.5	91.9	97.4	10,202	Coal	131,610	12,003	3,159,446	4,666,887	1.51	35.46
14	7							Gas - G						
15	Scherer 3 (2)	214.1	123,390	77.5	97.0	79.9	10,182	Coal			1,256,326	2,252,376	1.83	#N/A
16	Scholz 1	46.0	18,390	53.7	94.0	57.2	12,363	Coal	9,327	12,188	227,355	411,886	2.24	44.16
17	Scholz 2	46.0	18,720	54.7	96.0	57.0	12,405	Coal	9,526	12,188	232,215	420,662	2.25	44.16
18	Smith 1	162.0	93,110	77.3	98.1	78.7	10,383	Coal	40,214	12,020	966,745	1,440,454	1.55	35.82
19	Smith 2	192.6	119,230	83.2	96.9	85.9	10,249	Coal	50,834	12,020	1,222,036	1,820,885	1.53	35.82
20	Smith A (CT)	31.6	270	1.1	100.0	1.1	14,081	Oil - G	652	138,839	3,802	12,827	4.75	19.67
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	146,580	77.3	92.9	83.2	10,204	Coal	69,662	10,735	1,495,693	2,354,579	1.61	33.80
23	Daniel 2 (1)	255.0	153,420	80.9	94.1	85.9	10,169	Coal	72,660	10,735	1,560,064	2,455,905	1.60	33.80
24	Gas,BL							Gas	6,244	1,030	6,431	17,221	#N/A	2.76
25	Ltr. Oil							Oil	1,335	140,188	7,862	28,096	#N/A	21.04
26		2,210.3	1,287,010	78.3	95.2	82.2	10,381				13,360,938	21,190,671	1.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	5,690	31.9	97.4	32.7	17,650	Gas - G	97,506	1,030	100,431	268,921	4.73	2.76
2	1							Oil - G						
3	Crist 2	24.0	3,990	22.3	97.4	22.9	18,238	Gas - G	70,650	1,030	72,770	194,852	4.88	2.76
4	2							Oil - G						
5	Crist 3	35.0	10,460	40.2	97.4	41.2	15,993	Gas - G	162,420	1,030	167,292	447,956	4.28	2.76
6	3							Oil - G						
7	Crist 4	78.0	48,980	84.4	97.3	86.7	10,069	Coal	20,541	12,005	493,189	729,189	1.49	35.50
8	4							Gas - G						
9	Crist 5	80.0	47,670	80.1	97.7	82.0	10,298	Coal	20,445	12,005	490,884	725,811	1.52	35.50
10	5							Gas - G						
11	Crist 6	302.0	187,870	83.6	96.8	86.4	10,625	Coal	83,140	12,005	1,996,150	2,951,465	1.57	35.50
12	6							Gas - G						
13	Crist 7	465.0	317,060	91.6	91.9	99.7	10,190	Coal	134,572	12,005	3,230,877	4,777,314	1.51	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	125,480	78.8	97.0	81.2	10,171	Coal			1,276,230	2,278,698	1.82	#N/A
16	Scholz 1	46.0	20,770	60.7	94.0	64.6	12,268	Coal	10,509	12,123	254,801	467,760	2.25	44.51
17	Scholz 2	46.0	20,910	61.1	96.0	63.6	12,311	Coal	10,617	12,123	257,425	472,558	2.26	44.51
18	Smith 1	162.0	95,770	79.5	98.1	81.0	10,264	Coal	40,884	12,022	982,975	1,467,329	1.53	35.89
19	Smith 2	192.6	124,300	86.7	96.9	89.5	10,209	Coal	52,779	12,022	1,268,977	1,894,236	1.52	35.89
20	Smith A (CT)	31.6	310	1.3	100.0	1.3	14,052	Oil - G	746	138,981	4,356	14,793	4.77	19.82
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	154,580	81.5	92.9	87.7	10,127	Coal	71,884	10,889	1,565,415	2,487,885	1.61	34.61
23	Daniel 2 (1)	255.0	161,730	85.2	94.1	90.6	10,113	Coal	75,108	10,889	1,635,628	2,599,492	1.61	34.61
24	Gas,BL							Gas	6,244	1,030	6,431	17,221	#N/A	2.76
25	Ltr. Oil							Oil	1,335	140,235	7,862	28,162	#N/A	21.10
26		2,210.3	1,334,270	81.1	95.2	85.3	10,351				13,811,693	21,986,854	1.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	2,700	15.6	98.1	15.9	19,290	Gas - G	50,566	1,030	52,083	130,233	4.82	2.58
2	1							Oil - G						
3	Crist 2	24.0	940	5.4	99.2	5.5	19,685	Gas - G	17,965	1,030	18,504	46,269	4.92	2.58
4	2							Oil - G						
5	Crist 3	35.0	5,410	21.5	98.1	21.9	16,958	Gas - G	89,070	1,030	91,742	229,399	4.24	2.58
6	3							Oil - G						
7	Crist 4	78.0	32,780	58.4	71.4	81.7	10,142	Coal	13,845	12,006	332,446	491,342	1.50	35.49
8	4							Gas - G						
9	Crist 5	80.0	43,430	75.4	97.6	77.3	10,368	Coal	18,752	12,006	450,273	665,493	1.53	35.49
10	5							Gas - G						
11	Crist 6	302.0	165,710	76.2	96.8	78.7	10,658	Coal	73,551	12,006	1,766,150	2,610,316	1.58	35.49
12	6							Gas - G						
13	Crist 7	465.0	263,500	78.7	85.8	91.7	10,232	Coal	112,273	12,006	2,696,023	3,984,610	1.51	35.49
14	7							Gas - G						
15	Scherer 3 (2)	214.1	111,040	72.0	97.1	74.2	10,218	Coal			1,134,634	2,029,017	1.83	#N/A
16	Scholz 1	46.0	11,190	33.8	68.9	49.0	12,494	Coal	5,782	12,090	139,809	258,464	2.31	44.70
17	Scholz 2	46.0	14,630	44.2	96.0	46.0	12,582	Coal	7,612	12,090	184,069	340,248	2.33	44.70
18	Smith 1	162.0	82,840	71.0	98.2	72.3	10,360	Coal	35,691	12,023	858,226	1,282,730	1.55	35.94
19	Smith 2	192.6	104,890	75.6	96.9	78.1	10,181	Coal	44,414	12,023	1,067,925	1,596,244	1.52	35.94
20	Smith A (CT)	31.6	50	0.2	100.0	0.2	13,480	Oil - G	115	139,003	674	2,291	4.58	19.84
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	131,000	71.4	92.9	76.8	10,239	Coal	60,894	11,013	1,341,282	2,148,320	1.64	35.28
23	Daniel 2 (1)	255.0	100,880	54.9	69.0	79.6	10,238	Coal	46,890	11,013	1,032,843	1,654,265	1.64	35.28
24	Gas,BL							*Gas*	6,244	1,030	6,431	16,081	#N/A	2.58
25	Ltr. Oil							Oil	1,334	140,275	7,862	28,221	#N/A	21.15
26		2,210.3	1,079,410	67.8	89.6	75.7	10,358				11,180,976	17,671,502	1.64	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	12,007	0	0	#N/A	#N/A
8	4							Gas - G		1,030	0			
9	Crist 5	80.0	12,030	20.2	27.9	72.4	10,424	Coal	5,222	12,007	125,401	185,371	1.54	35.50
10	5							Gas - G						
11	Crist 6	302.0	168,540	75.0	96.8	77.5	10,666	Coal	74,855	12,007	1,797,568	2,657,336	1.58	35.50
12	6							Gas - G						
13	Crist 7	465.0	273,560	79.1	86.0	91.9	10,231	Coal	116,547	12,007	2,798,816	4,137,445	1.51	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	115,190	72.3	96.9	74.6	10,212	Coal			1,176,310	2,094,343	1.82	#N/A
16	Scholz 1	46.0	6,670	19.5	91.8	21.2	13,095	Coal	3,622	12,056	87,342	162,597	2.44	44.89
17	Scholz 2	46.0	5,350	15.6	69.4	22.5	13,138	Coal	2,915	12,056	70,286	130,849	2.45	44.89
18	Smith 1	162.0	86,390	71.7	98.1	73.1	10,352	Coal	37,190	12,023	894,271	1,338,474	1.55	35.99
19	Smith 2	192.6	111,330	77.7	96.9	80.2	10,089	Coal	46,710	12,023	1,123,259	1,681,087	1.51	35.99
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	69,530	36.6	45.0	81.4	10,164	Coal	31,831	11,101	706,721	1,137,959	1.64	35.75
23	Daniel 2 (1)	255.0	0	0.0	0.0	#DIV/0!	#N/A	Coal	0	11,101	0	0	#N/A	#N/A
24	Gas,BL							Gas	5,523	1,030	5,689	14,224	#N/A	2.58
25	Ltr. Oil							Oil	1,114	140,275	6,566	23,593	#N/A	21.17
26		2,210.3	857,290	52.1	71.1	73.3	10,256				8,792,229	13,726,490	1.60	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
6	3							Oil - G						
7	Crist 4	78.0	25,240	44.9	60.4	74.4	10,237	Coal	10,759	12,008	258,388	381,844	1.51	35.49
8	4							Gas - G						
9	Crist 5	80.0	26,580	46.1	96.9	47.6	10,488	Coal	11,608	12,008	278,778	411,968	1.55	35.49
10	5							Gas - G						
11	Crist 6	302.0	155,990	71.7	96.8	74.1	10,682	Coal	69,380	12,008	1,666,280	2,462,282	1.58	35.49
12	6							Gas - G						
13	Crist 7	465.0	271,500	81.1	85.8	94.5	10,217	Coal	115,494	12,008	2,773,804	4,098,889	1.51	35.49
14	7							Gas - G						
15	Scherer 3 (2)	214.1	106,610	69.2	96.9	71.4	10,223	Coal			1,089,910	1,949,136	1.83	#N/A
16	Scholz 1	46.0	6,390	19.3	95.1	20.3	13,096	Coal	3,477	12,034	83,684	156,490	2.45	45.01
17	Scholz 2	46.0	6,660	20.1	97.9	20.5	13,129	Coal	3,633	12,034	87,441	163,531	2.46	45.01
18	Smith 1	162.0	56,690	48.6	68.8	70.6	10,242	Coal	24,145	12,024	580,639	869,705	1.53	36.02
19	Smith 2	192.6	87,460	63.1	77.5	81.4	10,080	Coal	36,662	12,024	881,626	1,320,563	1.51	36.02
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,420									157,959	1.88	#N/A
22	Daniel 1 (1)	255.0	94,140	51.3	65.0	78.9	10,186	Coal	42,997	11,151	958,919	1,548,313	1.64	36.01
23	Daniel 2 (1)	255.0	114,890	62.6	78.3	79.9	10,027	Coal	51,655	11,151	1,152,036	1,860,088	1.62	36.01
24	Gas,BL							Gas	6,244	1,030	6,431	17,681	#N/A	2.83
25	Ltr. Oil							Oil	1,334	140,338	7,862	28,313	#N/A	21.23
26		2,210.3	960,570	60.4	83.8	72.0	10,229				9,825,798	15,426,762	1.61	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
2	1							Oil - G						
3	Crist 2	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	1,030	0	0	#N/A	#N/A
4	2							Oil - G						
5	Crist 3	35.0	0	0.0	100.0	0.0	#N/A	Gas - G	20	1,030	21	58	#N/A	2.90
6	3							Oil - G						
7	Crist 4	78.0	40,130	69.2	95.3	72.6	10,276	Coal	17,170	12,009	412,389	609,528	1.52	35.50
8	4							Gas - G						
9	Crist 5	80.0	36,400	61.2	95.7	63.9	10,598	Coal	16,062	12,009	385,777	570,209	1.57	35.50
10	5							Gas - G						
11	Crist 6	302.0	153,380	68.3	96.8	70.5	10,701	Coal	68,339	12,009	1,641,366	2,426,050	1.58	35.50
12	6							Gas - G						
13	Crist 7	465.0	258,420	74.7	86.0	86.9	10,259	Coal	110,387	12,009	2,651,218	3,918,722	1.52	35.50
14	7							Gas - G						
15	Scherer 3 (2)	214.1	99,580	62.5	96.9	64.5	10,282	Coal			1,023,886	1,841,512	1.85	#N/A
16	Scholz 1	46.0	6,600	19.3	95.0	20.3	13,089	Coal	3,593	12,022	86,390	161,978	2.45	45.08
17	Scholz 2	46.0	6,880	20.1	97.8	20.6	13,128	Coal	3,756	12,022	90,318	169,315	2.46	45.08
18	Smith 1	162.0	73,070	60.6	98.1	61.8	10,526	Coal	31,983	12,024	769,127	1,152,672	1.58	36.04
19	Smith 2	192.6	82,970	57.9	81.3	71.2	10,160	Coal	35,051	12,024	842,942	1,263,233	1.52	36.04
20	Smith A (CT)	31.6	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
21	Other Generation		8,700									163,212	1.88	#N/A
22	Daniel 1 (1)	255.0	122,360	64.5	92.9	69.4	10,316	Coal	56,413	11,188	1,262,297	2,042,699	1.67	36.21
23	Daniel 2 (1)	255.0	128,550	67.8	94.1	72.0	10,126	Coal	58,180	11,188	1,301,754	2,106,678	1.64	36.21
24	Gas,BL							Gas	6,244	1,030	6,431	18,134	#N/A	2.90
25	Ltr. Oil							Oil	1,334	140,368	7,862	28,352	#N/A	21.26
26		2,210.3	1,017,040	61.8	92.6	66.8	10,306				10,481,778	16,472,352	1.62	

Notes:
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SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2000 - DECEMBER 2000

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 1	24.0	15,640	7.4	95.2	7.8	18,063	Gas - G	274,285		282,512	741,340	4.74	2.70
2	1							Oil - G	0		0			
3	Crist 2	24.0	10,000	4.7	95.3	5.0	18,585	Gas - G	180,437	1,030	185,851	490,177	4.90	2.72
4	2							Oil - G	0		0			
5	Crist 3	35.0	29,380	9.6	95.2	10.0	16,252	Gas - G	463,568	1,030	477,476	1,252,345	4.26	2.70
6	3							Oil - G	0		0			
7	Crist 4	78.0	461,000	67.3	82.8	81.3	10,145	Coal	194,967	11,994	4,676,784	6,906,801	1.50	35.43
8	4							Gas - G	0		0			
9	Crist 5	80.0	468,500	66.7	90.7	73.5	10,388	Coal	202,883	11,995	4,866,995	7,188,131	1.53	35.43
10	5							Gas - G	0		0			
11	Crist 6	302.0	1,774,910	66.9	84.3	79.4	10,629	Coal	786,122	11,999	18,865,426	27,866,616	1.57	35.45
12	6							Gas - G	0		0	0		
13	Crist 7	465.0	2,947,160	72.2	77.3	93.3	10,235	Coal	1,257,216	11,997	30,165,564	44,560,627	1.51	35.44
14	7							Gas - G	0		0			
15	Scherer 3 (2)	214.1	1,250,730	66.5	89.0	74.7	10,210	Coal			12,770,128	23,003,584	1.84	#N/A
16	Scholz 1	46.0	138,570	34.3	89.5	38.3	12,592	Coal	71,055	12,278	1,744,816	3,101,861	2.24	43.65
17	Scholz 2	46.0	125,480	31.1	79.2	39.2	12,625	Coal	64,563	12,269	1,584,233	2,821,724	2.25	43.70
18	Smith 1	162.0	943,250	66.3	90.6	73.2	10,332	Coal	405,603	12,014	9,745,443	14,437,586	1.53	35.60
19	Smith 2	192.6	1,233,320	72.9	89.2	81.7	10,137	Coal	520,382	12,013	12,502,280	18,502,267	1.50	35.56
20	Smith A (CT)	31.6	960	0.3	100.0	0.3	13,830	Oil - G	2,275	138,981	13,277	44,787	4.67	19.69
21	Other Generation		102,720									1,927,026	1.88	#N/A
22	Daniel 1 (1)	251.0	1,368,470	62.1	75.3	82.4	10,237	Coal	664,873	10,535	14,008,996	21,708,597	1.59	32.65
23	Daniel 2 (1)	251.0	1,401,820	63.6	74.5	85.3	10,105	Coal	676,133	10,475	14,165,371	21,865,975	1.56	32.34
24	Gas,BL							Gas	70,799	0	72,921	192,650	#N/A	2.72
25	Ltr. Oil							Oil	15,551	139,978	91,424	322,069	#N/A	20.71
26		2,202.3	12,271,910	63.4	82.8	76.6	10,285				126,219,497	196,934,163	1.60	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
15	*PURCHASES :*													
16	UNITS (BBL)	1,508	997	905	977	994	1,006	1,329	1,325	1,327	1,107	1,326	1,326	14,127
17	UNIT COST ($/BBL)	21.80	21.62	21.62	21.61	21.62	21.62	21.58	21.58	21.57	21.59	21.58	21.57	21.62
18	AMOUNT ($)	32,868	21,559	19,570	21,114	21,489	21,749	28,679	28,594	28,626	23,900	28,614	28,607	305,369
20	*BURNED :*													
21	UNITS (BBL)	1,344	1,342	1,082	1,321	1,338	1,338	1,335	1,335	1,334	1,114	1,334	1,334	15,551
22	UNIT COST ($/BBL)	19.80	20.06	20.35	20.35	20.47	20.56	21.05	21.10	21.16	21.18	21.22	21.25	20.71
23	AMOUNT ($)	26,611	26,925	22,018	26,884	27,388	27,506	28,096	28,162	28,221	23,593	28,313	28,352	322,069
24	*ENDING INVENTORY :*													
25	UNITS (BBL)	7,647	7,302	7,125	6,781	6,437	6,105	6,099	6,089	6,082	6,075	6,067	6,059	
26	UNIT COST ($/BBL)	19.69	19.88	20.03	20.20	20.36	20.52	20.64	20.74	20.83	20.91	20.99	21.06	
27	AMOUNT ($)	150,537	145,171	142,723	136,953	131,054	125,297	125,880	126,312	126,717	127,024	127,325	127,580	
29	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
30	*PURCHASES :*													
31	UNITS (TONS)	542,000	436,761	272,028	376,434	409,357	423,213	437,758	446,920	386,267	406,494	396,505	407,688	4,941,425
32	UNIT COST ($/TON)	34.27	33.46	34.54	36.21	36.10	36.21	36.24	36.25	36.13	36.18	36.18	36.18	35.65
33	AMOUNT ($)	18,575,569	14,613,315	9,396,676	13,629,827	14,778,417	15,322,642	15,864,082	16,200,811	13,955,422	14,706,555	14,345,535	14,751,529	176,140,380
34	*BURNED :*													
35	UNITS (TONS)	410,805	344,116	264,523	372,935	427,761	489,105	504,733	520,479	419,704	318,892	369,810	400,934	4,843,797
36	UNIT COST ($/TON)	33.01	32.77	34.46	33.75	34.36	35.03	35.38	35.68	35.82	35.85	35.89	35.97	34.88
37	AMOUNT ($)	13,559,495	11,275,604	9,115,874	12,587,322	14,699,319	17,133,249	17,858,376	18,573,039	15,032,032	11,431,118	13,273,673	14,421,084	168,960,185
38	*ENDING INVENTORY :*													
39	UNITS (TONS)	1,095,494	1,188,139	1,195,644	1,199,143	1,180,739	1,114,847	1,047,872	974,313	940,876	1,028,478	1,055,173	1,061,927	
40	UNIT COST ($/TON)	32.68	32.95	32.97	33.75	34.34	34.75	35.06	35.28	35.38	35.56	35.67	35.76	
41	AMOUNT ($)	35,806,178	39,143,889	39,424,691	40,467,196	40,546,294	38,735,687	36,741,393	34,369,165	33,292,555	36,567,992	37,639,854	37,970,299	
43	DAYS SUPPLY:	48	52	52	52	52	49	46	43	41	45	46	46	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
44	*PURCHASES :*													
45	UNITS (MMBTU)	744,802	396,132	1,264,748	1,184,950	1,129,192	1,263,552	1,061,681	1,205,301	1,103,279	1,217,363	1,111,568	1,028,365	12,710,933
46	UNIT COST ($/MMBTU)	1.92	1.99	1.79	1.79	1.79	1.76	1.81	1.78	1.79	1.77	1.79	1.81	1.80
47	AMOUNT ($)	1,430,479	788,652	2,270,195	2,116,834	2,018,468	2,228,147	1,919,225	2,145,291	1,975,047	2,160,792	1,994,753	1,858,921	22,906,804
48	*BURNED :*													
49	UNITS (MMBTU)	744,199	343,985	1,248,273	1,166,701	1,101,970	1,207,704	1,256,326	1,276,230	1,134,634	1,176,310	1,089,910	1,023,886	12,770,128
50	UNIT COST ($/MMBTU)	1.85	1.89	1.84	1.81	1.80	1.78	1.79	1.79	1.79	1.78	1.79	1.80	1.80
51	AMOUNT ($)	1,374,365	649,838	2,292,463	2,111,428	1,981,436	2,148,972	2,252,376	2,278,698	2,029,017	2,094,343	1,949,136	1,841,512	23,003,584
52	*ENDING INVENTORY :*													
53	UNITS (MMBTU)	951,591	1,003,738	1,020,213	1,038,462	1,065,684	1,121,532	926,887	855,958	824,603	865,656	887,314	891,793	
54	UNIT COST ($/MMBTU)	1.85	1.89	1.84	1.81	1.80	1.78	1.79	1.79	1.79	1.78	1.79	1.80	
55	AMOUNT ($)	1,757,137	1,895,951	1,873,683	1,879,089	1,916,121	1,995,296	1,662,145	1,528,738	1,474,768	1,541,217	1,586,834	1,604,243	
57	DAYS SUPPLY:	22	23	23	24	24	25	21	19	19	20	20	20	
	GAS													
58	*BURNED :*													
59	UNITS (MCF)	7,222	8,442	5,853	6,680	8,185	116,468	317,543	336,820	163,845	5,523	6,244	6,264	989,089
60	UNIT COST ($/MCF)	2.90	2.83	2.83	2.58	2.58	2.58	2.76	2.76	2.58	2.58	2.83	2.90	2.71
61	AMOUNT ($)	20,974	23,905	16,573	17,204	21,080	299,963	875,784	928,950	421,982	14,224	17,681	18,192	2,676,512
	OTHER - C.T. OIL													
62	*PURCHASES :*													
63	UNITS (BBL)	658	50	71	0	65	37	653	746	115	0	0	0	2,395
64	UNIT COST ($/BBL)	21.53	21.36	21.56	#N/A	21.60	21.68	21.52	21.54	21.46	#N/A	#N/A	#N/A	21.53
65	AMOUNT ($)	14,165	1,068	1,531	0	1,404	802	14,055	16,072	2,468	0	0	0	51,565
66	*BURNED :*													
67	UNITS (BBL)	539	50	71	0	65	37	652	746	115	0	0	0	2,275
68	UNIT COST ($/BBL)	19.49	19.62	19.54	#N/A	19.60	19.65	19.67	19.83	19.92	#N/A	#N/A	#N/A	19.69
69	AMOUNT ($)	10,507	981	1,387	0	1,274	727	12,827	14,793	2,291	0	0	0	44,787
70	*ENDING INVENTORY :*													
71	UNITS (BBL)	8,570	8,570	8,570	8,570	8,570	8,570	8,571	8,571	8,571	8,571	8,571	8,571	
72	UNIT COST ($/BBL)	19.48	19.49	19.51	19.51	19.53	19.54	19.68	19.83	19.85	19.85	19.85	19.85	
73	AMOUNT ($)	166,983	167,070	167,214	167,214	167,344	167,419	168,647	169,926	170,103	170,103	170,103	170,103	
75	DAYS SUPPLY:	107	107	107	107	107	107	107	107	107	107	107	107	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
MONTH		KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
JANUARY								
1	Southern Co. Interchange	93,944,000	0	93,944,000	1.40	1.61	1,319,000	1,513,000
2	Unit Power Sales	42,890,000	0	42,890,000	2.00	2.12	856,000	908,000
3	Economy Sales	3,310,000	0	3,310,000	3.17	3.20	105,000	106,000
4	80% Gain on Economy Sales						10,000	12,000
5	Other Sales	200,000		200,000	2.00	2.00	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	140,344,000	0	140,344,000	1.63	1.81	2,294,000	2,543,000
FEBRUARY								
1	Southern Co. Interchange	70,946,000	0	70,946,000	1.49	1.67	1,060,000	1,182,000
2	Unit Power Sales	35,680,000	0	35,680,000	1.98	2.10	705,000	748,000
3	Economy Sales	4,180,000	0	4,180,000	3.11	3.16	130,000	132,000
4	80% Gain on Economy Sales						12,000	15,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	110,996,000	0	110,996,000	1.72	1.87	1,911,000	2,081,000
MARCH								
1	Southern Co. Interchange	41,798,000	0	41,798,000	1.63	1.81	680,000	756,000
2	Unit Power Sales	78,000,000	0	78,000,000	1.94	2.09	1,517,000	1,627,000
3	Economy Sales	18,880 000	0	18,880,000	2.81	2.90	530,000	548,000
4	80% Gain on Economy Sales						49,000	61,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	138,868,000	0	138,868,000	2.00	2.16	2,780,000	2,996,000
APRIL								
1	Southern Co. Interchange	153,236,000	0	153,236,000	1.58	1.78	2,417,000	2,728,000
2	Unit Power Sales	37,920,000	0	37,920,000	1.85	1.97	700,000	748,000
3	Economy Sales	22,410,000	0	22,410,000	2.85	2.92	639,000	654,000
4	80% Gain on Economy Sales						58,000	72,000
5	Other Sales	190,000		190,000	1.58	1.58	3,000	3,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	213,756,000	0	213,756,000	1.79	1.97	3,817,000	4,205,000
MAY								
1	Southern Co. Interchange	107,866,000	0	107,866,000	1.89	2.11	2,042,000	2,277,000
2	Unit Power Sales	71,680,000	0	71,680,000	1.91	2.04	1,366,000	1,460,000
3	Economy Sales	5,680,000	0	5,680,000	3.10	3.13	176,000	178,000
4	80% Gain on Economy Sales						16,000	20,000
5	Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	185,416,000	0	185,416,000	1.94	2.12	3,604,000	3,939,000
JUNE								
1	Southern Co. Interchange	107,051,000	0	107,051,000	1.97	2.18	2,107,000	2,333,000
2	Unit Power Sales	87,590,000	0	87,590,000	1.88	2.01	1,649,000	1,762,000
3	Economy Sales	9,320,000	0	9,320,000	3.26	3.36	304,000	313,000
4	80% Gain on Economy Sales						28,000	35,000
5	Other Sales	180,000		180,000	2.22	2.78	4,000	5,000
6	SEPA	0	0	0	#N/A	#N/A	0	0
7	TOTAL ESTIMATED SALES	204,141,000	0	204,141,000	2.00	2.18	4,092,000	4,448,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

LINE	(1) MONTH	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (A) ¢ / KWH FUEL COST	(6) (B) ¢ / KWH TOTAL COST	(7) (6) x (7)(A) TOTAL $ FOR FUEL ADJUSTMENT	(8) (6) x (7)(B) TOTAL COST $
	JULY								
1		Southern Co. Interchange	126,590,000	0	126,590,000	2.44	2.65	3,083,000	3,357,000
2		Unit Power Sales	101,360,000	0	101,360,000	1.90	2.03	1,930,000	2,062,000
3		Economy Sales	14,190,000	0	14,190,000	3.55	3.69	504,000	523,000
4		80% Gain on Economy Sales						47,000	59,000
5		Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6		SEPA	0	0	0	#N/A	#N/A	0	0
7		TOTAL ESTIMATED SALES	242,330,000	0	242,330,000	2.30	2.48	5,568,000	6,005,000
	AUGUST								
1		Southern Co. Interchange	164,683,000	0	164,683,000	2.36	2.58	3,883,000	4,252,000
2		Unit Power Sales	94,940,000	0	94,940,000	1.90	2.03	1,802,000	1,925,000
3		Economy Sales	8,170,000	0	8,170,000	3.60	3.75	294,000	306,000
4		80% Gain on Economy Sales						28,000	35,000
5		Other Sales	190,000		190,000	2.63	2.63	5,000	5,000
6		SEPA	0	0	0	#N/A	#N/A	0	0
7		TOTAL ESTIMATED SALES	267,983,000	0	267,983,000	2.24	2.43	6,012,000	6,523,000
	SEPTEMBER								
1		Southern Co. Interchange	105,072,000	0	105,072,000	2.00	2.21	2,101,000	2,327,000
2		Unit Power Sales	70,740,000	0	70,740,000	1.90	2.03	1,341,000	1,436,000
3		Economy Sales	7,970,000	0	7,970,000	3.01	3.11	240,000	248,000
4		80% Gain on Economy Sales						22,000	28,000
5		Other Sales	190,000		190,000	2.11	2.11	4,000	4,000
6		SEPA	0	0	0	#N/A	#N/A	0	0
7		TOTAL ESTIMATED SALES	183,972,000	0	183,972,000	2.02	2.20	3,708,000	4,043,000
	OCTOBER								
1		Southern Co. Interchange	89,753,000	0	89,753,000	1.56	1.74	1,398,000	1,558,000
2		Unit Power Sales	31,040,000	0	31,040,000	1.79	1.91	555,000	594,000
3		Economy Sales	37,370,000	0	37,370,000	1.95	2.10	729,000	785,000
4		80% Gain on Economy Sales						67,000	84,000
5		Other Sales	190,000		190,000	1.58	1.58	3,000	3,000
6		SEPA	0	0	0	#N/A	#N/A	0	0
7		TOTAL ESTIMATED SALES	158,353,000	0	158,353,000	1.74	1.91	2,752,000	3,024,000
	NOVEMBER								
8		Southern Co. Interchange	170,986,000	0	170,986,000	1.43	1.63	2,440,000	2,782,000
9		Unit Power Sales	35,880,000	0	35,880,000	1.75	1.85	628,000	665,000
10		Economy Sales	37,590,000	0	37,590,000	1.92	2.07	723,000	777,000
11		80% Gain on Economy Sales						67,000	83,000
12		Other Sales	180,000		180,000	1.67	1.67	3,000	3,000
13		SEPA	0	0	0	#N/A	#N/A	0	0
14		TOTAL ESTIMATED SALES	244,636,000	0	244,636,000	1.58	1.76	3,861,000	4,310,000
	DECEMBER								
15		Southern Co. Interchange	159,670,000	0	159,670,000	1.43	1.64	2,291,000	2,613,000
16		Unit Power Sales	41,450,000	0	41,450,000	1.84	1.97	761,000	818,000
17		Economy Sales	19,960,000	0	19,960,000	2.01	2.12	402,000	423,000
18		80% Gain on Economy Sales						36,000	45,000
19		Other Sales	190,000		190,000	1.58	2.11	3,000	4,000
20		SEPA	0	0	0	#N/A	#N/A	0	0
21		TOTAL ESTIMATED SALES	221,270,000	0	221,270,000	1.58	1.76	3,493,000	3,903,000
	TOTAL								
22		Southern Co. Interchange	1,391,595,000	0	1,391,595,000	1.78	1.99	24,821,000	27,678,000
23		Unit Power Sales	729,170,000	0	729,170,000	1.89	2.02	13,810,000	14,753,000
24		Economy Sales	189,030,000	0	189,030,000	2.53	2.64	4,776,000	4,993,000
25		80% Gain on Economy Sales						440,000	549,000
26		Other Sales	2,270,000	0	2,270,000	1.98	2.07	45,000	47,000
27		SEPA	0	0	0	#N/A	#N/A	0	0
28		TOTAL ESTIMATED SALES	2,312,065,000	0	2,312,065,000	1.90	2.08	43,892,000	48,020,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				260,000	1.661	1.661	4,319
FEBRUARY	Solutia	COG-1				40,000	1.661	1.661	664
MARCH	Solutia	COG-1				220,000	1.661	1.661	3,654
APRIL	Solutia	COG-1				260,000	2.324	2.324	6,042
MAY	Solutia	COG-1				570,000	2.324	2.324	13,247
JUNE	Solutia	COG-1				810,000	2.324	2.324	18,824
JULY	Solutia	COG-1				2,900,000	2.324	2.324	67,396
AUGUST	Solutia	COG-1				3,380,000	2.324	2.324	78,551
SEPTEMBER	Solutia	COG-1				530,000	2.324	2.324	12,317
OCTOBER	Solutia	COG-1				160,000	2.324	2.324	3,718
NOVEMBER	Solutia	COG-1				-	1.745	1.745	0
DECEMBER	Solutia	COG-1				-	1.745	1.745	0
TOTAL			0			9,130,000			208,732

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY				
1		Southern Co. Interchange	60,190,000	2.26	1,358,000
2		Unit Power Sales	4,670,000	2.25	105,000
3		Economy Energy	2,250,000	2.67	60,000
4		Other Purchases	4,360,000	3.49	152,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	71,470,000	2.34	1,675,000
	FEBRUARY				
1		Southern Co. Interchange	55,710,000	1.65	917,000
2		Unit Power Sales	5,880,000	2.09	123,000
3		Economy Energy	2,210,000	2.71	60,000
4		Other Purchases	3,750,000	3.44	129,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	67,550,000	1.82	1,229,000
	MARCH				
1		Southern Co. Interchange	195,000,000	1.94	3,785,000
2		Unit Power Sales	3,890,000	1.85	72,000
3		Economy Energy	3,220,000	3.20	103,000
4		Other Purchases	7,980,000	3.45	275,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	210,090,000	2.02	4,235,000
	APRIL				
1		Southern Co. Interchange	38,600,000	1.58	611,000
2		Unit Power Sales	4,660,000	1.80	84,000
3		Economy Energy	8,080,000	3.38	273,000
4		Other Purchases	4,920,000	3.29	162,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	56,260,000	2.01	1,130,000
	MAY				
1		Southern Co. Interchange	49,670,000	1.69	838,000
2		Unit Power Sales	1,070,000	2.43	26,000
3		Economy Energy	4,400,000	2.86	126,000
4		Other Purchases	4,540,000	3.44	156,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	59,680,000	1.92	1,146,000
	JUNE				
1		Southern Co. Interchange	31,440,000	1.79	564,000
2		Unit Power Sales	1,840,000	2.45	45,000
3		Economy Energy	4,760,000	2.98	142,000
4		Other Purchases	32,270,000	8.38	2,705,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	70,310,000	4.92	3,456,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY				
1		Southern Co. Interchange	29,110,000	1.59	463,000
2		Unit Power Sales	2,420,000	2.93	71,000
3		Economy Energy	4,790,000	2.88	138,000
4		Other Purchases	65,400,000	8.74	5,716,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	101,720,000	6.28	6,388,000
	AUGUST				
1		Southern Co. Interchange	18,520,000	1.54	286,000
2		Unit Power Sales	2,270,000	2.95	67,000
3		Economy Energy	4,690,000	3.62	170,000
4		Other Purchases	60,940,000	9.12	5,555,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	86,420,000	7.03	6,078,000
	SEPTEMBER				
1		Southern Co. Interchange	79,700,000	1.88	1,495,000
2		Unit Power Sales	1,240,000	2.50	31,000
3		Economy Energy	3,870,000	2.71	105,000
4		Other Purchases	18,820,000	3.99	750,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	103,630,000	2.30	2,381,000
	OCTOBER				
1		Southern Co. Interchange	88,940,000	1.47	1,310,000
2		Unit Power Sales	4,320,000	1.64	71,000
3		Economy Energy	2,650,000	1.77	47,000
4		Other Purchases	2,000,000	3.30	66,000
5		SEPA	0	#N/A	0
6		TOTAL ESTIMATED PURCHASES	97,910,000	1.53	1,494,000
	NOVEMBER				
7		Southern Co. Interchange	22,280,000	1.38	307,000
8		Unit Power Sales	10,250,000	1.60	164,000
9		Economy Energy	3,050,000	1.87	57,000
10		Other Purchases	1,630,000	3.31	54,000
11		SEPA	0	#N/A	0
12		TOTAL ESTIMATED PURCHASES	37,210,000	1.56	582,000
	DECEMBER				
13		Southern Co. Interchange	100,360,000	1.43	1,431,000
14		Unit Power Sales	2,210,000	1.76	39,000
15		Economy Energy	7,010,000	1.93	135,000
16		Other Purchases	460,000	3.26	15,000
17		SEPA	0	#N/A	0
18		TOTAL ESTIMATED PURCHASES	110,040,000	1.47	1,620,000
	TOTAL FOR PERIOD				
19		Southern Co. Interchange	769,520,000	1.74	13,365,000
20		Unit Power Sales	44,720,000	2.01	898,000
21		Economy Energy	50,980,000	2.78	1,416,000
22		Other Purchases	207,070,000	7.60	15,735,000
23		SEPA	0	#N/A	0
24		TOTAL ESTIMATED PURCHASES	1,072,290,000	2.93	31,414,000

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 - DECEMBER 2000

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Base Rate Revenues	$	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	47.23	566.76
Fuel Factor	¢/KWH	1.866	1.814	1.924	1.817	1.807	2.017	2.220	2.213	1.906	1.838	1.895	1.883	1.950
Group Loss Multiplier		1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228	1.01228
Fuel Adjustment Revenues	$	18.89	18.36	19.48	18.39	18.29	20.42	22.47	22.40	19.29	18.61	19.18	19.06	234.84
TOTAL REVENUES	$	66.12	65.59	66.71	65.62	65.52	67.65	69.70	69.63	66.52	65.84	66.41	66.29	804.56

*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2000	JANUARY	1.661
	FEBRUARY	1.661
	MARCH	1.661
	APRIL	2.324
	MAY	2.324
	JUNE	2.324
	JULY	2.324
	AUGUST	2.324
	SEPTEMBER	2.324
	OCTOBER	2.324
	NOVEMBER	1.745
	DECEMBER	1.745
2001	JANUARY	1.745
	FEBRUARY	1.745
	MARCH	1.745
	APRIL	2.349
	MAY	2.349
	JUNE	2.349
	JULY	2.349
	AUGUST	2.349
	SEPTEMBER	2.349
	OCTOBER	2.349
	NOVEMBER	1.778
	DECEMBER	1.778

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 1997 - DECEMBER 2000

LINE	LINE DESCRIPTION	YEAR 1997	1998	1999	2000	DIFFERENCE (%) FROM PRIOR PERIOD 1997 to 1998	1998 to 1999	1999 to 2000
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
2	LIGHTER OIL	386,593	364,122	392,387	322,069	(5.81)	7.76	(17.92)
3	COAL	185,356,130	166,226,834	166,188,239	168,960,185	(10.32)	(0.02)	1.67
3a	COAL at Scherer	21,509,221	20,791,702	20,044,252	23,003,584	(3.34)	(3.59)	14.76
4	GAS	1,253,954	3,485,743	3,344,750	2,483,862	177.98	(4.04)	(25.74)
4a	GAS (B.L.)	315,971	73	0	192,650	(99.98)	(100.00)	#N/A
6	OTHER - C.T.	49,883	155,984	171,403	44,787	212.70	9.88	(73.87)
6a	OTHER GENERATION	0	498,557	1,981,161	1,927,026	#N/A	297.38	(2.73)
7	TOTAL ($)	208,871,752	191,523,015	192,122,192	196,934,163	(8.31)	0.31	2.50
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
9	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
10	COAL	10,800,620	11,557,450	12,334,820	12,113,210	7.01	6.73	(1.80)
11	GAS	22,580	96,120	103,260	55,020	325.69	7.43	(46.72)
13	OTHER - C.T.	830	2,340	2,490	960			
13	OTHER GENERATION	0	32,290	123,900	102,720	#N/A	283.71	(17.09)
14	TOTAL (MWH)	10,824,030	11,688,200	12,564,470	12,271,910	7.98	7.50	(2.33)
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	0	0	0	0	#N/A	#N/A	#N/A
16	LIGHTER OIL (BBL)	16,990	13,751	13,445	15,551	(19.06)	(2.23)	15.66
17	COAL excl. Scherer (TON)	4,523,720	4,827,753	5,247,061	4,843,797	6.72	8.69	(7.69)
18	GAS (MCF)	640,532	1,379,160	1,458,111	989,089	115.31	5.72	(32.17)
20	OTHER - C.T.	2,005	5,599	5,978	2,275	179.25	6.77	(61.94)
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	0	0	0	0	#N/A	#N/A	#N/A
22	LIGHTER OIL	0	0	0	0	#N/A	#N/A	#N/A
23	COAL + GAS B.L. + OIL B.L.	112,845,802	120,501,564	128,393,814	125,260,381	6.78	6.55	(2.44)
24	GAS - Generation	552,879	1,420,511	1,501,853	945,839	156.93	5.73	(37.02)
26	OTHER - C.T.	11,740	32,882	35,115	13,277	180.09	6.79	(62.19)
27	TOTAL (MMBTU)	113,410,421	121,954,957	129,930,782	126,219,497	7.53	6.54	(2.86)
	GENERATION MIX (% MWH)							
28	HEAVY OIL	0.00	0.00	0.00	0.00	#N/A	#N/A	#N/A
29	LIGHTER OIL	0.00	0.00	0.00	0.00	#N/A	#N/A	#N/A
30	COAL + GAS B.L. + OIL B.L.	99.78	98.88	98.17	98.70	(0.90)	(0.72)	0.54
31	GAS - Generation	0.21	0.82	0.82	0.45	290.48	0.00	(45.12)
33	OTHER - C.T.	0.01	0.02	0.02	0.01	100.00	0.00	(50.00)
33a	OTHER GENERATION	0.00	0.28	0.99	0.84	#N/A	253.57	(15.15)
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
35	HEAVY OIL ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
36	LIGHTER OIL B.L. ($/BBL)	22.75	26.48	29.18	20.71	16.40	10.20	(29.03)
37	COAL ($/TON)	40.97	34.43	31.67	34.88	(15.96)	(8.02)	10.14
38	GAS +B.L. ($/MCF)	2.45	2.53	2.29	2.71	3.27	(9.49)	18.34
40	OTHER - C.T.	24.88	27.86	28.67	19.69	11.98	2.91	(31.32)
	FUEL COST ($) / MMBTU							
41	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
42	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
43	COAL + GAS B.L. + OIL B.L.	1.84	1.56	1.45	1.54	(15.22)	(7.05)	6.21
44	GAS - Generation	2.27	2.45	2.23	2.63	7.93	(8.98)	17.94
46	OTHER - C.T.	4.25	4.74	4.88	3.37	11.53	2.95	(30.94)
47	TOTAL ($/MMBTU)	1.84	1.57	1.46	1.54	(14.67)	(7.01)	5.48
	BTU BURNED / KWH							
48	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
49	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
50	COAL + GAS B.L. + OIL B.L.	10,448	10,426	10,409	10,341	(0.21)	(0.16)	(0.65)
51	GAS - Generation	24,485	14,779	14,544	17,191	(39.64)	(1.59)	18.20
53	OTHER - C.T.	14,145	14,052	14,102	13,830	(0.66)	0.36	(1.93)
54	TOTAL (BTU/KWH)	10,478	10,434	10,341	10,285	(0.42)	(0.89)	(0.54)
	FUEL COST (¢ / KWH)							
55	HEAVY OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
56	LIGHTER OIL	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
57	COAL + GAS B.L. + OIL B.L.	1.92	1.62	1.51	1.59	(15.63)	(6.79)	5.30
58	GAS - Generation	5.55	3.63	3.24	4.51	(34.59)	(10.74)	39.20
60	OTHER - C.T.	6.01	6.67	6.88	4.67	10.98	3.15	(32.12)
60a	OTHER GENERATION	#N/A	1.54	1.60	1.88	#N/A	3.90	17.50
61	TOTAL (¢ / KWH)	1.93	1.64	1.53	1.60	(15.03)	(6.71)	4.58

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2000 - December 2000

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) ($)	624,443	268,960	117,797	(5,448)	311,532	(691,878)	(752,400)	(324,720)	(630,168)	13,154	(87,516)	114,804	(1,041,440)
2	Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Projected Market Capacity Payments	305,177	305,177	305,177	312,902	312,902	2,108,102	3,269,702	3,269,702	1,580,102	418,502	418,502	418,502	13,024,449
4	Total Projected Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	991,822	636,339	485,176	369,656	686,636	1,478,426	2,579,504	3,007,184	1,012,136	493,858	393,188	595,508	12,729,433
5	Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271
6	Projected Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	956,937	613,957	468,111	356,654	662,485	1,426,426	2,488,775	2,901,413	976,536	476,488	379,358	574,562	12,281,702
7	Amount Included in Retail Base Rate Revenues ($)	(137,666)	(137,666)	(137,666)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(1,652,000)
8	Jurisdictional Amount to be Recovered (Line 6 - Line 7) ($)	1,094,603	751,623	605,777	494,321	800,152	1,564,093	2,626,442	3,039,080	1,114,203	614,155	517,025	712,228	13,933,702
9	*True-Up* ($)													(68,182)
10	Total Jurisdictional Amount to be Recovered (Line 8 + Line 9) ($)													13,865,520
11	Revenue Tax Multiplier													1.01597
12	Total Recoverable Capacity Payments/(Receipts) (Line 10 x Line 11) ($)													14,086,953

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,637,521.41	96.48271%
FERC	59,696.01	3.51729%
Total	1,697,217.42	100.00000%

* Based on 1997 Actual Data

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2000 - December 2000

1	Estimated over/(under)-recovery, January 1999 - December 1999 (Schedule CCE-1b-1, Line 17)	($12,942)
2	Final True-Up, October 1997 - September 1998 (Exhibit No.____(TAD-1), filed April 1, 1999	(95,729)
3	Final True-Up, October 1998 - December 1998 (Exhibit No.____(TAD-1), filed April 1, 1999	176,853
4	Total Over/(Under)-Recovery	$68,182
5	Jurisdictional KWH sales, January 2000 - December 2000	10,013,721,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0007)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 1999 - December 1999

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	829,072	696,859	472,257	437,944	565,742	602,518	(628,894)	1,139,814	58,136	27,752	(11,780)	109,269	4,298,689
2	Projected Capacity Payments to Monsanto ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Projected Market Capacity Payments									674,991	398,379	398,379	390,962	1,862,711
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	891,274	759,061	534,459	500,146	627,944	664,720	(566,692)	1,202,016	795,329	488,333	448,801	562,433	6,907,824
5	Jurisdictional %	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	0.9648271	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	859,925	732,363	515,660	482,555	605,857	641,340	(546,760)	1,159,738	767,355	471,157	433,015	542,651	6,664,856
7	Amount Included in Retail Base Rate Revenues ($)	(137,667)	(137,667)	(137,667)	(137,667)	(137,666)	(137,666)	(137,667)	(137,667)	(137,666)	(137,667)	(137,667)	(137,666)	(1,652,000)
8	Total Jurisdictional Recovery Amount (Line 6 - Line 7) ($)	997,592	870,030	653,328	620,222	743,525	779,007	(409,093)	1,297,405	905,021	608,824	570,682	680,317	8,316,860
9	Retail KWH Sales									876,848,000	702,438,000	659,165,000	791,003,000	
10	Purchased Power Capacity Cost Recovery Factor (¢/KWH)									0.102	0.102	0.102	0.102	
11	Capacity Cost Recovery Revenues (Line 9 x Line 10/100) ($)	767,136	622,643	646,079	723,608	813,135	955,600	1,077,304	1,122,427	894,385	716,487	672,348	806,823	9,817,975
12	Revenue Taxes (Line 11 x .01572) ($)	12,059	9,788	10,156	11,375	12,782	15,022	16,935	17,645	14,060	11,263	10,569	12,683	154,337
13	True-Up Provision ($)	(109,597)	(109,597)	(109,597)	(109,597)	(109,597)	(109,597)	(109,598)	(109,597)	(109,597)	(109,597)	(109,598)	(109,598)	(1,315,167)
14	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 11 - Line 12 + Line 13) ($)	645,480	503,258	526,326	602,636	690,756	830,981	950,771	995,185	770,728	595,627	552,181	684,542	8,348,471
15	Over/(Under) Recovery (Line 14 - Line 8) ($)	(352,112)	(366,772)	(127,002)	(17,586)	(52,769)	51,974	1,359,864	(302,220)	(134,293)	(13,197)	(18,501)	4,225	31,611
16	Interest Provision ($)	(5,483)	(6,483)	(7,113)	(6,954)	(6,661)	(6,411)	(3,151)	(477)	(677)	(798)	(394)	49	(44,553)
17	Total Estimated True-Up for the Period January 1999 - December 1999 (Line 15 + Line 16) ($)													(12,942)

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2000 - December 2000

	A	B	C	D	E	F	G	H	I
Rate Class	Average 12 CP Load Factor at Meter	Jan - Dec 00 Projected KWH Sales at Meter	Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Jan - Dec 00 Projected KWH Sales at Generation Col B x Col E	Projected Avg 12 CP KW at Generation Col C x Col D	Percentage of KWH Sales at Generation Col F / Total Col F	Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RST	57.217702%	4,669,455,000	931,604.71	1.1019333	1.0766175	5,027,216,968	1,026,566.25	47.18085%	56.09219%
GS, GST	57.820776%	263,808,000	52,083.47	1.1019255	1.0766135	284,019,254	57,392.10	2.66554%	3.13594%
GSD, GSDT	72.316857%	2,195,727,000	346,604.90	1.1016647	1.0764011	2,363,482,958	381,842.38	22.18148%	20.86409%
LP, LPT	85.738506%	1,088,382,000	144,910.99	1.0601470	1.0444167	1,136,724,337	153,626.95	10.66825%	8.39427%
PX, PXT, RTP, SBS	97.623712%	1,680,197,000	196,472.05	1.0313379	1.0235079	1,719,694,903	202,629.07	16.13947%	11.07177%
OS-I, OS-II	299.917227%	87,532,000	3,331.67	1.1020255	1.0766162	94,238,369	3,671.59	0.88443%	0.20062%
OS-III	98.962375%	23,970,000	2,764.99	1.1024447	1.0766529	25,807,370	3,048.25	0.24220%	0.16656%
OS-IV	34.482597%	3,739,000	1,237.80	1.1024447	1.0766529	4,025,605	1,364.61	0.03778%	0.07456%
TOTAL	67.948463%	10,012,810,000	1,679,010.58			10,655,209,764	1,830,141.20	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 1997 load research data.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
January 2000 - December 2000

Rate Class	A Jan - Dec 00 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 00 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RST	47.18086%	56.09219%	511,258	7,293,859	7,805,117	4,669,455,000	0.167
GS, GST	2.66554%	3.13594%	28,884	407,777	436,661	263,808,000	0.166
GSD, GSDT	22.18147%	20.86409%	240,361	2,713,029	2,953,390	2,195,727,000	0.135
LP, LPT	10.66825%	8.39427%	115,602	1,091,536	1,207,138	1,088,382,000	0.111
PX, PXT, RTP, SBS	16.13947%	11.07177%	174,889	1,439,700	1,614,589	1,680,197,000	0.096
OS-I, OS-II	0.88443%	0.20062%	9,584	26,087	35,671	87,532,000	0.041
OS-III	0.24220%	0.16656%	2,625	21,658	24,283	23,970,000	0.101
OS-IV	0.03778%	0.07456%	409	9,695	10,104	3,739,000	0.270
TOTAL	100.00000%	100.00000%	$1,083,612	$13,003,341	$14,086,953	10,012,810,000	0.141

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY, 2000 - DECEMBER, 2000

Contract		MW Purchase/(Sale)	Capacity ($) Costs/(Receipts)
Southern Company Intercompany Interchange			
	January 2000	331.4	624,443
	February	346.7	268,960
	March	143.4	117,797
	April	(23.4)	(5,448)
	May	391.4	311,532
	June	(95.3)	(691,878)
	July	(38.0)	(752,400)
	August	(16.4)	(324,720)
	September	(68.2)	(630,168)
	October	31.6	13,154
	November	(132.6)	(87,516)
	December	275.4	114,804
	SUBTOTAL		(1,041,440)
Solutia			
	January 2000	19.0	62,202
	February	19.0	62,202
	March	19.0	62,202
	April	19.0	62,202
	May	19.0	62,202
	June	19.0	62,202
	July	19.0	62,202
	August	19.0	62,202
	September	19.0	62,202
	October	19.0	62,202
	November	19.0	62,202
	December	19.0	62,202
	SUBTOTAL		746,424

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 25
COMPANY/ WITNESS: Howell
DATE: 11-22-99

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY, 2000 - DECEMBER, 2000

Contract	Capacity ($) Costs/(Receipts)
Market Capacity Purchases	
January 2000	305,177
February	305,177
March	305,177
April	312,902
May	312,902
June	2,108,102
July	3,269,702
August	3,269,702
September	1,580,102
October	418,502
November	418,502
December	418,502
SUBTOTAL	13,024,449
TOTAL	**12,729,433**

EXHIBIT NO. 26

DOCKET NO: 990001-EI

WITNESS: M.W. HOWELL

PARTY: GULF POWER COMPANY

DESCRIPTION: GULF POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 1)

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 26
COMPANY/ WITNESS: PSC Staff
DATE: 11-22-99

1. Please indicate whether Gulf calculates the 80%/20% incentive mechanism, as set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, on non-separated wholesale energy sales other than economy energy sales made through Energy Broker Network (formerly known as the Florida Energy Broker System). If so, please respond to the following:

   a. Please identify all other types of non-separated wholesale energy sales on which Gulf calculates the 80%/20% incentive mechanism.

   b. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a, above, please indicate the authority which requires or permits Gulf to calculate the 80%/20% incentive mechanism on such sales.

   c. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a. above, please indicate on an annual basis from 1990 to 1998 the amount of and total revenues from energy sold by Gulf.

   d. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a above, please indicate on an annual basis from 1990 to 1998 the generation-related gain on such sales by Gulf. For purposes of responding to this interrogatory, the generation gain should be defined as total revenue received on a wholesale energy sale minus the sum of the following: incremental fuel costs, incremental O&M costs, and any transmission charge paid by the purchaser.

ANSWER:

Gulf Power Company calculates the 80%/20% incentive mechanism on non-separated wholesale economy energy sales not made through the Energy Broker Network. Gulf does not make economy energy sales through the Energy Broker Network.

   a. Gulf calculates the 80%/20% incentive mechanism on all of its non-separated wholesale economy energy sales, none of which are made through the Energy Broker Network. These sales are categorized by Gulf Power as "economy" sales and "external" sales to differentiate the sales based on whether they are made to non-affiliated utilities that are directly interconnected to the Southern electric system ("economy") or to non-affiliated utilities and power marketers that are <u>not</u> directly interconnected to the Southern electric system ("external").

b. In Order No. 12663 issued November 11, 1983 in Docket No. 830012-EU (TECO's rate case) the Commission decided to review in the next fuel adjustment proceeding whether or not gains from economy sales should be removed from base rates and considered in the fuel clause. In the generic fuel docket, No. 830001-EU-B, the Commission concluded in Order No. 12923 issued January 25, 1985 that it was appropriate to remove the profits associated with economy energy sales from base rates for all of the investor owned electric utilities and to include 80% of such profits in the fuel clause beginning April 1, 1984. To facilitate the change from base rate recovery to fuel clause recovery, the Commission "directed the utilities to provide the dollar amount of economy sales profits included in base rates in their most recent rate case." Gulf Power complied with this directive in a letter to the FPSC dated February 3, 1984. The staff reviewed this information along with similar information supplied by the other affected utilities and compiled a composite spreadsheet for the utilities to review. The composite spreadsheet was sent to Gulf and the other affected utilities by letter from Staff Counsel M. Robert Christ dated February 10, 1984. In Order No. 13092 (issued March 16, 1984 in Docket No. 840001-EU), the Commission acknowledged that the utilities' filings for the fuel cost recovery period beginning April 1, 1984 included ". . . economy energy sales profits in their projections for the April – September 1984 period based on the 80%/20% split between the ratepayers and the shareholders. Because the economy energy sales profits are currently in base rates, it is also necessary to adjust the base rates to exclude these profits as of April 1, 1984." A review of Schedule C attached to that order shows the adjustment to base rates proposed by Gulf was agreed to by staff and the 80%/20% split between the ratepayers and the shareholders for Gulf's economy energy sales. At that time, all of Gulf's economy energy sales were Schedule C economy sales made pursuant to FERC regulated interchange agreements between the operating companies of the Southern Company ("the Southern electric system") and non-affiliated utilities directly interconnected with the Southern electric system. Public Counsel appealed the Commission's order regarding the treatment of profits made by utilities in economy energy sales. The Florida Supreme Court affirmed the Commission's order in this case on February 28, 1985. Gulf has continued to include 80% of the profit associated with Schedule C economy sales as a credit to ratepayers through the fuel clause.

Since 1995, in addition to Gulf's Schedule C economy sales, the Company has made economy sales to utilities that are not directly interconnected with the Southern electric system (external sales) that include a markup similar to Schedule C economy sales. Gulf has consistently applied the directive of Order No. 12923 regarding the 80%/20% split of gain on economy sales to all of its non-separated wholesale economy sales, both those made to directly interconnected utilities (internally classified as "economy") and those to utilities that are not directly interconnected (internally classified as "external").

c. Total Revenues Associated with Gulf's Non-separated Wholesale Energy Sales:

	Economy Sales		External Sales	
	Kwh	$	Kwh	$
1990	162,650,533	4,533,012	0	0
1991	34,087,642	944,372	0	0
1992	16,088,539	463,988	0	0
1993	59,132,645	1,714,384	0	0
1994	101,899,768	3,166,783	0	0
1995	44,339,013	1,327,585	277,927	6,435
1996	32,849,547	969,109	11,298,332	281,274
1997	76,641,743	2,212,222	61,543,208	1,850,438
1998	52,436,553	1,590,115	27,376,440	1,282,630

d. Generation-related Gains on Gulf's Non-separated Wholesale Energy Sales:

	Economy Sales	External Sales
	$	$
1990	742,959	0
1991	110,737	0
1992	50,099	0
1993	188,615	0
1994	320,847	0
1995	157,890	0
1996	86,758	0
1997	370,782	369,979
1998	257,606	669,167

Before The

Florida Public Service Commission

Tampa Electric Company

Docket No. 990001-EI

In Re: Fuel and Purchased Power Cost Recovery

and

Capacity Cost Recovery

Final True-Ups

April 1998 through December 1998

Testimony & Exhibit of

Karen O. Zwolak

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 17
COMPANY/ WITNESS: Zwolak
DATE 11-22-99

DOCUMENT NUMBER-DATE
04198 APR-19

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

INDEX

Document No.	Title	Page
1	Final Fuel Over-Recovery For April 1998 - December 1998	1
2	Actual True-Up vs. Original Estimates	2
3	Final Capacity Cost Over-Recovery for April 1998 - December 1998	3
4	Commission Schedules A1 - A9 April 1998 - December 1998	9
5	Temporary Base Rate Reduction	160

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 1
PAGE 1 OF 1
REVISED 9/29/99

TAMPA ELECTRIC COMPANY

FINAL FUEL OVER-RECOVERY

FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

1	TOTAL FUEL COSTS FOR THE PERIOD	$281,149,525
2	JURISDICTIONAL FUEL COSTS (INCL. PEABODY, FMPA CREDIT, AND OIL BELOW THE DISCHARGE VALVE)	$281,501,223
3	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	298,335,319
4	ACTUAL OVER-RECOVERED FUEL COSTS FOR THE PERIOD EXCLUDING INTEREST (LINE 3 - LINE 2)	$16,834,096
5	INTEREST	257,908
6	ACTUAL OVER-RECOVERY FOR THE PERIOD INCLUDING INTEREST (LINE 4 + LINE 5)	$17,092,004
7	ACTUAL/ESTIMATED OVER-RECOVERY APPROVED AT THE NOVEMBER 1998 (SCH. E-1A/LINE 5) FUEL HEARINGS FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998.	9,212,068
8	FINAL FUEL OVER-RECOVERY (LINE 6 - LINE 7)	**$7,879,936**

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 1
PAGE 1 OF 1

TAMPA ELECTRIC COMPANY

FINAL FUEL OVER-RECOVERY

FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

1	TOTAL FUEL COSTS FOR THE PERIOD	$281,149,525
2	JURISDICTIONAL FUEL COSTS (INCL. PEABODY, FMPA CREDIT, AND OIL BELOW THE DISCHARGE VALVE)	$281,501,223
3	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	298,335,319
4	ACTUAL OVER-RECOVERED FUEL COSTS FOR THE PERIOD EXCLUDING INTEREST (LINE 3 - LINE 2)	$16,834,096
5	INTEREST	257,908
6	ACTUAL OVER-RECOVERY FOR THE PERIOD INCLUDING INTEREST (LINE 4 + LINE 5)	$17,092,004
7	ACTUAL/ESTIMATED OVER-RECOVERY APPROVED AT THE NOVEMBER 1998 (SCH. E-1A/LINE 5) FUEL HEARINGS FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998.	5,261,113
8	FINAL FUEL OVER-RECOVERY (LINE 6 - LINE 7)	**$11,830,891**

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 2
PAGE 1 OF 1

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs ORIGINAL ESTIMATES
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A	1. FUEL COST OF SYSTEM NET GENERATION	$271,295,719	$302,221,867	($30,926,148)	(10.2)
	2. FUEL COST OF POWER SOLD *	23,933,645	33,025,960	(9,092,315)	(27.5)
	3. FUEL COST OF PURCHASED POWER	27,170,987	12,911,000	14,259,987	110.4
	a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	b. PAYMENT TO QUALIFIED FACILITIES	6,385,581	7,571,400	(1,185,819)	(15.7)
	4. ENERGY COST OF ECONOMY PURCHASES	262,737	1,502,800	(1,240,063)	(82.5)
	6a. ADJUSTMENTS TO FUEL COST	(31,854)	(30,000)	(1,854)	6.2
	6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0
	6c. ADJ.TO FUEL COST	0	0	0	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. (Sum of Lines A1 through A6c)	$281,149,525	$291,151,107	($10,001,582)	(3.4)
C	1. JURISDICTIONAL FUEL REVENUE	$289,412,510	$280,688,029	$8,724,481	3.1
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	a. TRUE-UP PROVISION	8,377,490	8,377,490	0	0.0
	b. INCENTIVE PROVISION	545,319	545,320	(1)	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2b)	298,335,319	289,610,839	8,724,480	3.0
	6B.JURISDICTIONAL FUEL COST	277,792,221	288,654,867	(10,862,646)	(3.8)
	6D.PEABODY CONTRACT BUY OUT AMORT. JURISD.	3,724,464	3,740,121	(15,657)	(0.4)
	6E.FUEL CREDIT DIFFERENTIAL-FMPA/LKL SALE	(13,179)	(2,938,153)	2,924,974	(99.6)
	6F.OIL BELOW THE DISCHARGE VALVE	(2,283)	0	(2,283)	0.0
	6G.JURISD. TOTAL FUEL & NET PWR. TRANS. (LINES 6B + 6D + 6E + 6F)	281,501,223	289,456,835	(7,955,612)	(2.7)
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6G)	16,834,096	154,004	16,680,092	
	8. INTEREST PROVISION - THIS PERIOD	257,908	82,095	175,813	
	8a.TOTAL TRUE-UP AMOUNT FOR APRIL 1998 THROUGH DECEMBER 1998	$17,092,004	$236,099	$16,855,905	

Line numbers reference Schedule A-2 included in Document No. 4
* Includes Economy Sales Profits (80%)

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 3
PAGE 1 OF 6

FINAL CAPACITY COST OVER RECOVERY

FOR APRIL 1998 THROUGH DECEMBER 1998

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

	APRIL 1998 THROUGH SEPTEMBER 1998	OCTOBER 1998 THROUGH DECEMBER 1998
1. End-of-Period True-up: Over/(Under) Recovery	($312,716)	($732,421) INCL. T-UP ENDING SEPT. $9,675
2. Less: Actual/ Estimated Over/(Under) Recovery Approved at the November 1998 Fuel Hearings for the April 1998 through December 1998 period	(322,391)	(1,175,420)
3. Net True-up: Over/(Under) Recovery to be carried forward to the January 2000 through December 2000 period	$9,675	**$442,999**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) ACTUAL JUNE	(4) ACTUAL JULY	(5) ACTUAL AUGUST	(6) ACTUAL SEPTEMBER	TOTAL APR.-SEPT. 1998	(7) ACTUAL OCTOBER	(8) ACTUAL NOVEMBER	(9) ACTUAL DECEMBER	TOTAL OCT.-DEC. 1998
1. UNIT POWER CAPACITY CHARGES	$1,116,918	$1,124,117	$1,116,918	$1,116,918	$1,116,918	$1,116,918	$6,708,707	$1,116,918	$930,632	$1,127,607	$3,175,157
2. CAPACITY PAYMENTS TO COGENERATORS	1,079,650	1,079,650	1,079,650	1,079,650	1,079,650	1,079,650	6,477,900	1,079,650	1,079,650	1,079,650	3,238,950
3. EMERGENCY CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0
4. (CAPACITY REVENUES)	(150,129)	(136,205)	(97,717)	(101,659)	(138,133)	(106,808)	(730,651)	(84,349)	(93,180)	(62,439)	(239,968)
5. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$2,046,439	$2,067,562	$2,098,851	$2,094,909	$2,058,435	$2,089,760	$12,455,956	$2,112,219	$1,917,102	$2,144,818	$6,174,139
6. JURISDICTIONAL PERCENTAGE	98.46438%	98.46438%	98.46438%	98.46438%	98.46438%	98.46438%	-	98.46438%	98.46438%	98.46438%	-
7. JURISDICTIONAL CAPACITY PAYMENTS	$2,015,013	$2,035,812	$2,066,621	$2,062,739	$2,026,825	$2,057,669	$12,264,679	$2,079,783	$1,887,663	$2,111,882	$6,079,328
8. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	1,641,778	1,738,759	2,257,278	2,416,453	2,263,755	2,304,333	12,622,356	2,109,461	1,748,239	1,807,270	5,664,970
9. PRIOR PERIOD TRUE-UP PROVISION	(49,797)	(49,797)	(49,797)	(49,797)	(49,797)	(49,797)	(298,782)	(107,464)	(107,464)	(107,463)	(322,391)
10. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$1,591,981	$1,688,962	$2,207,481	$2,366,656	$2,213,958	$2,254,536	$12,323,574	$2,001,997	$1,640,775	$1,699,807	$5,342,579
11. TRUE-UP PROVISION FOR MONTH - OVER/ (UNDER) RECOVERY (LINE 10 - LINE 7)	($423,032)	($346,850)	$140,860	$303,917	$187,133	$196,867	$58,895	($77,786)	($246,888)	($412,075)	($736,749)
12. INTEREST PROVISION FOR MONTH	(3,846)	(5,389)	(5,695)	(4,481)	(3,108)	(1,945)	(24,464)	(1,281)	(1,565)	(2,501)	(5,347)
13. TRUE-UP & INTEREST PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(298,782)	(675,863)	(978,305)	(793,343)	(444,110)	(210,288)	(298,782)	(322,391)	(293,994)	(434,983)	(322,391)
14. DEFERRED TRUE-UP - OVER/(UNDER) RECOVERY	(347,147)	(347,147)	(347,147)	(347,147)	(347,147)	(347,147)	(347,147)	9,675	9,675	9,675	9,675
15. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS MONTH	49,797	49,797	49,797	49,797	49,797	49,797	298,782	107,464	107,464	107,463	322,391
16. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	($1,023,010)	($1,325,452)	($1,140,490)	($791,257)	($557,435)	($312,716)	($312,716)	($284,319)	($425,308)	($732,421)	($732,421)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD APRIL 1998 THROUGH DECEMBER 1998

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) ACTUAL JUNE	(4) ACTUAL JULY	(5) ACTUAL AUGUST	(6) ACTUAL SEPTEMBER	(7) ACTUAL OCTOBER	(8) ACTUAL NOVEMBER	(9) ACTUAL DECEMBER	(10) TOTAL
1. BEGINNING TRUE-UP AMOUNT	(645,929)	(1,023,010)	(1,325,452)	(1,140,490)	(791,257)	(557,435)	(312,716)	(284,319)	(425,308)	N/A
2. ENDING TRUE-UP AMOUNT BEFORE INTEREST	(1,019,164)	(1,320,063)	(1,134,795)	(786,776)	(554,327)	(310,771)	(283,038)	(423,743)	(729,920)	N/A
3. TOTAL BEGINNING & ENDING TRUE-UP AMOUNT (LINES 1 + 2)	(1,665,093)	(2,343,073)	(2,460,247)	(1,927,266)	(1,345,584)	(868,206)	(595,754)	(708,062)	(1,155,228)	N/A
4. AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(832,547)	(1,171,537)	(1,230,124)	(963,633)	(672,792)	(434,103)	(297,877)	(354,031)	(577,614)	N/A
5. INT. RATE % - FIRST DAY REP. BUS. MONTH	5.550	5.530	5.500	5.600	5.560	5.520	5.220	5.100	5.500	N/A
6. INT. RATE % - FIRST DAY SUBSEQUENT MONTH	5.530	5.500	5.600	5.560	5.520	5.220	5.100	5.500	4.900	N/A
7. TOTAL (LINE 5 + LINE 6)	11.080	11.030	11.100	11.160	11.080	10.740	10.320	10.600	10.400	N/A
8. AVERAGE INT. RATE % (50% OF LINE 7)	5.540	5.515	5.550	5.580	5.540	5.370	5.160	5.300	5.200	N/A
9. MONTHLY AVG. INT. RATE % (LINE 8/12)	0.462	0.460	0.463	0.465	0.462	0.448	0.430	0.442	0.433	N/A
10. INT. PROVISION (LINE 4 X LINE 9)	($3,846)	(5,389)	($5,695)	($4,481)	($3,108)	($1,945)	($1,281)	($1,565)	($2,501)	($29,811)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD APRIL 1998 THROUGH SEPTEMBER 1998

	(1) ACTUAL APR-SEP 98	(2) ACTUAL/ ESTIMATED APR-SEP 98	(3) VARIANCE (1)-(2)	(4) % CHANGE (3)/(2)
1. UNIT POWER CAPACITY CHARGES	$ 6,708,707	$ 6,690,289	$ 18,418	0.28%
2. CAPACITY PAYMENTS TO COGENERATORS	6,477,900	6,513,750	(35,850)	-0.55%
3. EMERGENCY CAPACITY CHARGES	0	0	0	0.00%
4. (CAPACITY REVENUES)	(730,651)	(756,843)	26,192	-3.46%
5. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$ 12,455,956	$ 12,447,196	$ 8,760	0.07%
6. JURISDICTIONAL PERCENTAGE	98.46438%	98.46438%	0.00000%	0.00%
7. JURISDICTIONAL CAPACITY PAYMENTS	$ 12,264,679	$ 12,256,054	$ 8,625	0.07%
8. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	12,622,356	12,604,126	18,230	0.14%
9. PRIOR PERIOD TRUE-UP PROVISION	(298,782)	(298,782)	0	0.00%
10. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$ 12,323,574	$ 12,305,344	$ 18,230	0.15%
11. TRUE-UP PROVISION FOR PERIOD - OVER/ (UNDER) RECOVERY (LINE 10 - LINE 7)	$ 58,895	$ 49,290	$ 9,605	19.49%
12. INTEREST PROVISION FOR PERIOD	(24,464)	(24,534)	70	-0.29%
13. TRUE-UP & INTEREST PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(298,782)	(298,782)	0	0.00%
14. DEFERRED TRUE-UP - OVER/(UNDER) RECOVERY	(347,147)	(347,147)	0	0.00%
15. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS PERIOD	298,782	298,782	0	0.00%
16. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	$ (312,716)	$ (322,391)	$ 9,675	-3.00%

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD OCTOBER 1998 THROUGH DECEMBER 1998

	(1) ACTUAL OCT-DEC 98	(2) ESTIMATED OCT-DEC 98	(3) VARIANCE (1)-(2)	(4) % CHANGE (3)/(2)
1. UNIT POWER CAPACITY CHARGES	$ 3,175,157	$ 3,295,500	$ (120,343)	-3.65%
2. CAPACITY PAYMENTS TO COGENERATORS	3,238,950	3,346,500	(107,550)	-3.21%
3. EMERGENCY CAPACITY CHARGES	0	0	0	N/A
4. (CAPACITY REVENUES)	(239,968)	(361,100)	121,132	-33.55%
5. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$ 6,174,139	$ 6,280,900	$ (106,761)	-1.70%
6. JURISDICTIONAL PERCENTAGE	98.46438%	98.46438%	0	0.00%
7. JURISDICTIONAL CAPACITY PAYMENTS	$ 6,079,328	6,184,449	(105,121)	-1.70%
8. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	5,664,970	5,340,568	324,402	6.07%
9. PRIOR PERIOD TRUE-UP PROVISION	(322,391)	(413,577)	91,186	-22.05%
10. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$ 5,342,579	$ 4,926,991	$ 415,588	8.43%
11. TRUE-UP PROVISION FOR PERIOD - OVER/ (UNDER) RECOVERY (LINE 10 - LINE 7)	$ (736,749)	$ (1,257,458)	$ 520,709	-41.41%
12. INTEREST PROVISION FOR PERIOD	(5,347)	(9,148)	3,801	-41.55%
13. TRUE-UP & INTEREST PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(322,391)	(413,577)	91,186	-22.05%
14. DEFERRED TRUE-UP - OVER/(UNDER) RECOVERY	9,675	91,186	(81,511)	-89.39%
15. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS PERIOD	322,391	413,577	(91,186)	-22.05%
16. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 15)	$ (732,421)	$ (1,175,420)	$ 442,999	-37.69%

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 4
PAGE 1 OF

COMMISSION SCHEDULES A1 - A9

APRIL 1998 - DECEMBER 1998

COMMISSION SCHEDULES A1 - A9

DECEMBER 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

SCHEDULE A1
REVISED LINE 7 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	25,000,193	30,477,777	(5,477,584)	(18.0)	1,192,976	1,398,180	(205,204)	(14.7)	2.09562	2.17982	(0.08420)	(3.9)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,564)	(3,000)	436	(14.5)	1,192,976 (a)	1,398,180 (a)	(205,204)	(14.7)	(0.00021)	(0.00021)	0.00000	0.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,192,976 (a)	1,398,180 (a)	(205,204)	(14.7)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,192,976 (a)	1,398,180 (a)	(205,204)	(14.7)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	24,997,629	30,474,777	(5,477,148)	(18.0)	1,192,976	1,398,180	(205,204)	(14.7)	2.09540	2.17960	(0.08420)	(3.9)
6. Fuel Cost of Purchased Power - Firm (A7)	1,718,461	837,800	880,661	105.1	61,746	19,052	42,694	224.1	2.78311	4.39744	(1.61433)	(36.7)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	(1,720)	7,400	(9,120)	(123.2)	0	301	(301)	(100.0)	0.00000	2.45847	(2.45847)	(100.0)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	741,407	567,300	174,107	30.7	37,815	38,569	(754)	(2.0)	1.96062	1.47087	0.48975	33.3
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	2,458,148	1,412,500	1,045,648	74.0	99,561	57,922	41,639	71.9	2.46899	2.43862	0.03037	1.2
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,292,537	1,456,102	(163,565)	(11.2)				
14. Fuel Cost of Economy Sales (A6)	163,951	2,187,800	(2,023,849)	(92.5)	10,360	158,506	(148,146)	(93.5)	1.58254	1.38026	0.20228	14.7
15. Gain on Economy Sales - 80% (A6)	18,797	606,880	(588,083)	(96.9)	10,360 (a)	158,506 (a)	(148,146)	(93.5)	0.18144	0.38288	(0.20144)	(52.6)
16. Fuel Cost of Sch. D Separ. Sales (A6)	430,430	479,000	(48,570)	(10.1)	30,941	31,129	(188)	(0.6)	1.39113	1.53876	(0.14763)	(9.6)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	32,126	86,100	(53,974)	(62.7)	1,987	5,662	(3,675)	(64.9)	1.61681	1.52066	0.09615	6.3
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	6,755	124,000	(117,245)	(94.6)	383	7,396	(7,013)	(94.8)	1.76371	1.67658	0.08713	5.2
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	122,268	29,300	92,968	317.3	4,804	1,234	3,570	289.3	2.54513	2.37439	0.17074	7.2
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	774,327	3,513,080	(2,738,753)	(78.0)	48,475	203,927	(155,452)	(76.2)	1.59737	1.72271	(0.12534)	(7.3)
23. Net Inadvertant Interchange					(430)	0	(430)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,234	0	1,234	0.0				
25. Interchange and Wheeling Losses					1,701	3,100	(1,399)	(45.1)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	26,681,450	28,374,197	(1,692,747)	(6.0)	1,243,165	1,249,075	(5,910)	(0.5)	2.14625	2.27162	(0.12537)	(5.5)
27. Net Unbilled	(1,766,900) (a)	88,252 (a)	(1,855,152)	(2,102.1)	(82,325)	3,885	(86,210)	(2,219.0)	(0.14213)	0.00707	(0.14920)	(2,110.3)
28. Company Use	82,437 (a)	77,235 (a)	5,202	6.7	3,841	3,400	441	13.0	0.00651	0.00655	(0.00004)	(0.6)
29. T & D Losses	1,198,766 (a)	1,406,996 (a)	(208,230)	(14.8)	55,854	61,938	(6,084)	(9.8)	0.09470	0.11925	(0.02455)	(20.6)
30. System KWH Sales	26,681,450	28,374,197	(1,692,747)	(6.0)	1,285,795	1,179,852	85,943	7.3	2.10788	2.40489	(0.29701)	(12.4)
31. Wholesale KWH Sales	(48,902)	(58,079)	9,177	(15.8)	(2,320)	(2,415)	95	(3.9)	2.10784	2.40493	(0.29709)	(12.4)
32. Jurisdictional KWH Sales	26,632,548	28,316,118	(1,683,570)	(5.9)	1,263,475	1,177,437	86,038	7.3	2.10788	2.40489	(0.29701)	(12.4)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	26,636,010	28,319,799	(1,683,789)	(5.9)	1,263,475	1,177,437	86,038	7.3	2.10815	2.40521	(0.29706)	(12.4)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	408,119	408,031	88	0.0	1,263,475	1,177,437	86,038	7.3	0.03230	0.03465	(0.00235)	(6.8)
36. Adjustment - Oil Below the Discharge Valve	2,639	0	2,639	0.0	1,263,475	1,177,437	86,038	7.3	0.00021	0.00000	0.00021	0.0
37. True-up *	(1,334,789)	(1,334,789)	0	0.0	1,263,475	1,177,437	86,038	7.3	(0.10564)	(0.11336)	0.00772	(6.8)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	25,711,979	27,393,041	(1,681,062)	(6.1)	1,263,475	1,177,437	86,038	7.3	2.03502	2.32650	(0.29148)	(12.5)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.03671	2.32843	(0.29172)	(12.5)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,263,475	1,177,437	86,038	7.3	(0.00480)	(0.00515)	0.00035	(6.8)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	25,651,388	27,332,450	(1,681,062)	(6.2)	1,263,475	1,177,437	86,038	7.3	2.03191	2.32328	(0.29137)	(12.5)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.032	2.323	(0.291)	(12.5)

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: DECEMBER, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	78,896,208	93,407,461	(14,511,253)	(15.5)	3,784,458	4,329,539	(545,081)	(12.6)	2.08474	2.15745	(0.07271)	(3.4)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,240)	(9,000)	1,760	(19.6)	3,784,458 (a)	4,329,539 (a)	(545,081)	(12.6)	(0.00019)	(0.00021)	0.00002	(9.5)
4b. Adjustments to Fuel Cost	0	0	0	0.0	3,784,458 (a)	4,329,539 (a)	(545,081)	(12.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	3,784,458 (a)	4,329,539 (a)	(545,081)	(12.6)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	78,888,968	93,398,461	(14,509,493)	(15.5)	3,784,458	4,329,539	(545,081)	(12.6)	2.08455	2.15724	(0.07269)	(3.4)
6. Fuel Cost of Purchased Power - Firm (A7)	7,078,918	2,488,500	4,590,418	184.5	292,038	66,156	225,882	341.4	2.42397	3.76156	(1.33759)	(35.6)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	78,417	61,300	17,117	27.9	2,346	2,053	293	14.3	3.34258	2.98587	0.35671	11.9
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	2,189,387	2,114,200	75,187	3.6	113,010	115,526	(2,516)	(2.2)	1.93734	1.83006	0.10728	5.9
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	9,346,722	4,664,000	4,682,722	100.4	407,394	183,735	223,659	121.7	2.29427	2.53844	(0.24417)	(9.6)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					4,191,852	4,513,274	(321,422)	(7.1)				
14. Fuel Cost of Economy Sales (A6)	837,664	7,053,100	(6,215,436)	(88.1)	52,673	495,501	(442,828)	(89.4)	1.59031	1.42343	0.16688	11.7
15. Gain on Economy Sales - 80% (A6)	102,281	2,071,520	(1,969,239)	(95.1)	52,673	495,501 (a)	(442,828)	(89.4)	0.19418	0.41807	(0.22389)	(53.6)
16. Fuel Cost of Sch. D Separ. Sales (A6)	1,183,987	1,423,000	(239,013)	(16.8)	93,294	92,343	951	1.0	1.26909	1.54099	(0.27190)	(17.6)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	182,166	264,600	(82,434)	(31.2)	11,233	16,998	(5,765)	(33.9)	1.62170	1.55665	0.06505	4.2
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	63,586	141,600	(78,014)	(55.1)	2,728	8,478	(5,750)	(67.8)	2.33087	1.67021	0.66066	39.6
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	701,455	301,800	399,655	132.4	28,917	12,832	16,085	125.4	2.42591	2.35193	0.07398	3.1
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,071,183	11,255,620	(8,184,437)	(72.7)	188,845	626,152	(437,307)	(69.8)	1.62630	1.79759	(0.17129)	(9.5)
23. Net Inadvertant Interchange					(97)	0	(97)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					2,603	0	2,603	0.0				
25. Interchange and Wheeling Losses					5,913	9,500	(3,587)	(37.8)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	85,164,507	86,806,841	(1,642,334)	(1.9)	3,999,600	3,877,622	121,978	3.1	2.12933	2.23866	(0.10933)	(4.9)
27. Net Unbilled	(3,393,833) (a)	(1,997,265) (a)	(1,396,568)	69.9	(159,385)	(89,217)	(70,168)	78.6	(0.08485)	(0.05151)	(0.03334)	64.7
28. Company Use	248,110 (a)	228,343 (a)	19,767	8.7	11,652	10,200	1,452	14.2	0.00622	0.00607	0.00015	2.5
29. T & D Losses	3,338,278 (a)	4,305,503 (a)	(967,225)	(22.5)	156,776	192,325	(35,549)	(18.5)	0.08365	0.11438	(0.03073)	(26.9)
30. System KWH Sales	85,164,507	86,806,841	(1,642,334)	(1.9)	3,990,557	3,764,314	226,243	6.0	2.13415	2.30605	(0.17190)	(7.5)
31. Wholesale KWH Sales	(475,114)	(260,138)	(214,976)	82.6	(21,911)	(11,395)	(10,516)	92.3	2.16838	2.28291	(0.11453)	(5.0)
32. Jurisdictional KWH Sales	84,689,393	86,546,703	(1,857,310)	(2.1)	3,968,646	3,752,919	215,727	5.7	2.13396	2.30612	(0.17216)	(7.5)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	84,700,402	86,557,954	(1,857,552)	(2.1)	3,968,646	3,752,919	215,727	5.7	2.13424	2.30642	(0.17218)	(7.5)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	1,227,670	1,230,526	(2,856)	(0.2)	3,968,646	3,752,919	215,727	5.7	0.03093	0.03279	(0.00186)	(5.7)
36. Adjustment - Oil Below the Discharge Valve	(2,283)	0	(2,283)	0.0	3,968,646	3,752,919	215,727	5.7	(0.00006)	0.00000	(0.00006)	0.0
37. True-up *	(4,004,369)	(4,004,369)	0	0.0	3,968,646	3,752,919	215,727	5.7	(0.10090)	(0.10670)	0.00580	(5.4)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	81,921,420	83,784,111	(1,862,691)	(2.2)	3,968,646	3,752,919	215,727	5.7	2.06422	2.23251	(0.16829)	(7.5)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.06593	2.23436	(0.16843)	(7.5)
41. GPIF * (Already Adjusted for Taxes)	181,773	181,773	0	0.0	3,968,646	3,752,919	215,727	5.7	0.00458	0.00484	(0.00026)	(5.4)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	82,103,193	83,965,884	(1,862,691)	(2.2)	3,968,646	3,752,919	215,727	5.7	2.07051	2.23920	(0.16869)	(7.5)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.071	2.239	(0.168)	(7.5)

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	25,000,193	30,477,777	(5,477,584)	(18.0)	78,896,208	93,407,461	(14,511,253)	(15.5)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	774,327	3,513,080	(2,738,753)	(78.0)	3,071,183	11,255,620	(8,184,437)	(72.7)
3. FUEL COST OF PURCHASED POWER	1,718,461	837,800	880,661	105.1	7,078,918	2,488,500	4,590,418	184.5
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	741,407	567,300	174,107	30.7	2,189,387	2,114,200	75,187	3.6
4. ENERGY COST OF ECONOMY PURCHASES	(1,720)	7,400	(9,120)	(123.2)	78,417	61,300	17,117	27.9
5. TOTAL FUEL & NET POWER TRANSACTION	26,684,014	28,377,197	(1,693,183)	(6.0)	85,171,747	86,815,841	(1,644,094)	(1.9)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(2,564)	(3,000)	436	(14.5)	(7,240)	(9,000)	1,760	(19.6)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	26,681,450	28,374,197	(1,692,747)	(6.0)	85,164,507	86,806,841	(1,642,334)	(1.9)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,263,475	1,177,437	86,038	7.3	3,968,646	3,752,919	215,727	5.7
2. NONJURISDICTIONAL SALES	2,320	2,415	(95)	(3.9)	21,911	11,395	10,516	92.3
3. TOTAL SALES	1,265,795	1,179,852	85,943	7.3	3,990,557	3,764,314	226,243	6.0
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9981672	0.9979531	0.0002141	0.0	0.9945093	0.9969729	(0.0024636)	(0.2)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

C. TRUE-UP CALCULATION	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
1. JURISDICTIONAL FUEL REVENUE	29,110,881	26,228,231	2,882,650	11.0	91,574,696	83,625,591	7,949,105	9.5
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	1,334,789	1,334,789	0	0.0	4,004,369	4,004,369	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	181,773	181,773	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	30,506,261	27,623,611	2,882,650	10.4	95,760,838	87,811,733	7,949,105	9.1
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	26,681,450	28,374,197	(1,692,747)	(6.0)	85,164,507	86,806,841	(1,642,334)	(1.9)
5. JURISDIC. SALES- % TOTAL KWH SALES (LINE B-4)	0.9981672	0.9979531	0.0002141	0.0	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	26,632,548	28,316,118	(1,683,570)	(5.9)	84,689,393	86,546,703	(1,857,310)	(2.1)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	26,636,010	28,319,799	(1,683,789)	(5.9)	84,700,402	86,557,954	(1,857,552)	(2.1)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	408,868	408,868	0	0.0	1,234,197	1,234,197	0	0.0
6D.(LINE 6C x LINE 5)	408,119	408,031	88	0.0	1,227,670	1,230,526	(2,856)	(0.2)
6E.FUEL CREDIT DIFFERENTIAL -FMPA	0	0	0	0.0	0	0	0	0.0
6F. OTHER ADJ.(OIL BELOW DISCHG. VALVE)	2,639	0	2,639	0.0	(2,283)	0	0	0.0
6G. JURISDIC. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND ADJUSTMENTS	27,046,768	28,727,830	(1,681,062)	(5.9)	85,925,789	87,788,480	(1,862,691)	(2.1)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6G)	3,459,493	(1,104,219)	4,563,712	(413.3)	9,835,049	23,253	9,811,796	42,195.8
8. INTEREST PROVISION FOR THE MONTH	52,075	6,392	45,683	714.7	127,914	42,057	85,857	204.1
9. TRUE-UP & INT. PROV. BEG. OF MONTH	10,910,856	2,444,512	8,466,344	346.3	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	53,414	53,414	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(1,334,789)	(1,334,789)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	13,141,049	65,310	13,075,739	20,021.0	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

SCHEDULE A2
PAGE 3 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	10,964,270	2,497,926	8,466,344	338.9	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	13,088,974	58,918	13,030,056	22,115.6	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	24,053,244	2,556,844	21,496,400	840.7	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	12,026,622	1,278,422	10,748,200	840.7	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.500	6.000	(0.500)	(8.3)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	4.900	6.000	(1.100)	(18.3)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	10.400	12.000	(1.600)	(13.3)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.200	6.000	(0.800)	(13.3)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.433	0.500	(0.067)	(13.4)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	52,075	6,392	45,683	714.7	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	81,574	73,832	7,742	10.5	936,010	476,337	459,673	96.5
2	LIGHT OIL	506,712	473,835	32,877	6.9	2,486,462	1,054,882	1,431,580	135.7
3	COAL	24,411,907	29,930,110	(5,518,203)	(18.4)	75,473,736	91,876,242	(16,402,506)	(17.9)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	25,000,193	30,477,777	(5,477,584)	(18.0)	78,896,208	93,407,461	(14,511,253)	(15.5)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	2,280	2,081	199	9.6	28,686	13,315	15,371	115.4
9	LIGHT OIL	18,505	15,043	3,462	23.0	78,805	32,119	46,686	145.4
10	COAL	1,172,191	1,381,056	(208,865)	(15.1)	3,676,967	4,284,105	(607,138)	(14.2)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,192,976	1,398,180	(205,204)	(14.7)	3,784,458	4,329,539	(545,081)	(12.6)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	4,625	4,628	(3)	(0.1)	58,920	30,440	28,480	93.6
16	LIGHT OIL (BBL)	28,605	20,977	7,628	36.4	126,341	47,437	78,904	166.3
17	COAL (TON)	552,925	630,940	(78,015)	(12.4)	1,698,643	1,951,811	(253,168)	(13.0)
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	29,046	29,255	(209)	(0.7)	371,476	192,408	179,068	93.1
22	LIGHT OIL	165,979	121,525	44,454	36.6	733,541	275,279	458,262	166.5
23	COAL	12,405,869	14,204,989	(1,799,120)	(12.7)	38,409,142	44,094,298	(5,685,156)	(12.9)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	12,600,894	14,355,769	(1,754,875)	(12.2)	39,514,159	44,561,985	(5,047,826)	(11.3)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.19	0.15	0.04	-	0.76	0.31	0.45	-
29	LIGHT OIL	1.55	1.08	0.47	-	2.08	0.74	1.34	-
30	COAL	98.26	98.77	(0.51)	-	97.16	98.95	(1.79)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	17.64	15.95	1.69	10.6	15.89	15.65	0.24	1.5
36	LIGHT OIL ($/BBL)	17.71	22.59	(4.88)	(21.6)	19.68	22.24	(2.56)	(11.5)
37	COAL ($/TON)	44.15	47.44	(3.29)	(6.9)	44.43	47.07	(2.64)	(5.6)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.81	2.52	0.29	11.5	2.52	2.48	0.04	1.6
42	LIGHT OIL	3.05	3.90	(0.85)	(21.8)	3.39	3.83	(0.44)	(11.5)
43	COAL	1.97	2.11	(0.14)	(6.6)	1.96	2.08	(0.12)	(5.8)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.98	2.12	(0.14)	(6.6)	2.00	2.10	(0.10)	(4.8)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: DECEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	12,739	14,058	(1,319)	(9.4)	12,950	14,450	(1,500)	(10.4)
49	LIGHT OIL	8,969	8,079	890	11.0	9,308	8,571	737	8.6
50	COAL	10,583	10,286	297	2.9	10,446	10,293	153	1.5
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,563	10,267	296	2.9	10,441	10,293	148	1.4
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.58	3.55	0.03	0.8	3.26	3.58	(0.32)	(8.9)
56	LIGHT OIL	2.74	3.15	(0.41)	(13.0)	3.16	3.28	(0.12)	(3.7)
57	COAL	2.08	2.17	(0.09)	(4.1)	2.05	2.14	(0.09)	(4.2)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.10	2.18	(0.08)	(3.7)	2.08	2.16	(0.08)	(3.7)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: DECEMBER, 1998

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPC. FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents /KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	34	-467	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	34	0	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	34	0	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	43	0	0.0	89.4	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	0	0.0	10.6	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	212	-467	0.0	69.6	0.0	0	HVY.OIL	687	6318923	4341.1	11515	0.00	16.76
GAN.#1	99	40645	55.2	99.5	79.5	11186	COAL	21384	21261401	454653.8	946711	2.33	44.27
GAN.#2	88	25765	39.4	79.5	75.5	12220	COAL	14776	21307837	314844.6	654162	2.54	44.27
GAN.#3	145	31526	29.2	69.7	69.8	11888	COAL	19853	18878321	374791.3	878930	2.79	44.27
GAN.#4	179	17789	13.4	21.0	47.2	12051	COAL	11359	18872982	214378.2	502885	2.83	44.27
GAN.#5	242	126200	70.1	92.6	72.2	10156	COAL	54097	23693539	1281749.4	2394978	1.90	44.27
GAN.#6	392	149032	51.1	64.3	59.4	10486	COAL	65809	23746659	1562743.9	2913490	1.95	44.27
GANNON STA.	1145	390957	45.9	68.4	64.5	10751	COAL	187278	22443433	4203161.2	8291156	2.12	44.27
B.B.#1	431	51654	16.1	21.6	60.3	11476	COAL	25950	22843441	592787.3	1083761	2.10	41.76
B.B.#2	431	205072	64.0	84.9	68.9	10316	COAL	91774	23052200	2115592.6	3832799	1.87	41.76
B.B.#3	404	169692	56.5	74.2	68.2	10924	COAL	84013	22064899	1853738.4	3508673	2.07	41.76
B.B. 1 - 3	1266	426418	45.3	59.9	65.7	10699	COAL	201737	22614187	4562118.3	8425233	1.98	41.76
B.B.#4	447	295834	89.0	97.6	89.7	9826	COAL	133375	21793979	2906772.0	6245172	2.11	46.82
B.B. STA.	1713	722252	56.7	69.8	72.0	10341	COAL	335112	22287744	7468890.3	14670405	2.03	43.78
SEB-PHIL. #1(HVY OIL)	17	1403	11.1	94.8	80.0	8994	HVY.OIL	2012	6271918	12619.1	35794	2.55	17.79
SEB-PHIL. #2(HVY OIL)	17	1344	10.6	93.8	80.4	8992	HVY.OIL	1926	6275130	12085.9	34265	2.55	17.79
SEB-PHILLIPS TOTAL	34	2747	10.9	94.3	80.2	8993	HVY.OIL	3938	6273489	24705.0	70059	2.55	17.79
POLK COAL	250	58982	31.7	37.5	84.6	12441	COAL	30535	24031999	733817.1	1450346	2.46	47.50
POLK OIL	245	18464	10.1	10.1	100.5	8912	LGT.OIL	28363	5801869	164558.4	502945	2.72	17.73
POLK TOTAL	250	77446	41.8	47.6	-	11600	-	-	-	898375.5	1953291	2.52	-
GAN.C.T.#1	17	10	0.1	100.0	9.8	5880	LGT.OIL	10	5880000	58.8	157	1.57	15.70
B.B.C.T.#1	17	6	0.0	100.0	35.3	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	80	13	0.0	100.0	16.3	43977	LGT.OIL	97	5893814	571.7	1509	11.61	15.56
B.B.C.T.#3	80	12	0.0	100.0	2.5	65850	LGT.OIL	135	5853333	790.2	2101	17.51	15.56
C.T. TOTAL	194	41	0.0	100.0	11.7	34651	LGT.OIL	242	5870661	1420.7	3767	9.19	15.57
TOT. COAL (GN,BB,POLK)	3108	1172191	50.7	66.7	70.2	10583	COAL	552925	22436802	12405868.6	24411907	2.08	44.15
SYSTEM	3548	1192976	45.2	68.9	62.9	10563	-	-	-	12600893.8	25000193	2.10	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)								
1	PURCHASES:								
2	UNITS (BBL)	12,213	4,628	7,585	163.9	109,536	30,440	79,096	259.8
3	UNIT COST ($/BBL)	(5.27)	15.81	(21.08)	(133.3)	13.22	15.02	(1.80)	(12.0)
4	AMOUNT ($)	(64,307)	73,158	(137,465)	(187.9)	1,447,628	457,149	990,479	216.7
5	BURNED:								
6	UNITS (BBL)	4,625	4,628	(3)	(0.1)	58,920	30,440	28,480	93.6
7	UNIT COST ($/BBL)	17.64	15.95	1.69	10.6	15.89	15.65	0.24	1.5
8	AMOUNT ($)	81,574	73,832	7,742	10.5	936,010	476,337	459,673	96.5
9	ENDING INVENTORY:								
10	UNITS (BBL)	180,469	127,276	53,193	41.8	180,469	127,276	53,193	41.8
11	UNIT COST ($/BBL)	13.33	14.31	(0.98)	(6.8)	13.33	14.31	(0.98)	(6.8)
12	AMOUNT ($)	2,405,377	1,821,429	583,948	32.1	2,405,377	1,821,429	583,948	32.1
13									
14	DAYS SUPPLY:	137	394	(257)	(65.2)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	48,068	32,634	15,434	47.3	169,965	84,622	85,343	100.9
17	UNIT COST ($/BBL)	14.21	23.29	(9.08)	(39.0)	19.37	22.85	(3.48)	(15.2)
18	AMOUNT ($)	683,033	760,001	(76,968)	(10.1)	3,291,543	1,933,853	1,357,690	70.2
19	BURNED:								
20	UNITS (BBL)	28,605	20,977	7,628	36.4	126,341	47,437	78,904	166.3
21	UNIT COST ($/BBL)	17.71	22.59	(4.88)	(21.6)	19.68	22.24	(2.56)	(11.5)
22	AMOUNT ($)	506,712	473,835	32,877	6.9	2,486,462	1,054,882	1,431,580	135.7
23	ENDING INVENTORY:								
24	UNITS (BBL)	49,550	76,883	(27,333)	(35.6)	49,550	76,883	(27,333)	(35.6)
25	UNIT COST ($/BBL)	17.34	22.34	(5.00)	(22.4)	17.34	22.34	(5.00)	(22.4)
26	AMOUNT ($)	859,185	1,717,864	(858,679)	(50.0)	859,185	1,717,864	(858,679)	(50.0)
27									
28	DAYS SUPPLY: NORMAL	45	72	(27)	(37.5)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	7	11	(4)	(36.4)	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	766,368	695,371	70,997	10.2	2,375,235	2,114,113	261,122	12.4
32	UNIT COST ($/TON)	41.42	47.35	(5.93)	(12.5)	42.88	47.27	(4.39)	(9.3)
33	AMOUNT ($)	31,740,394	32,927,809	(1,187,415)	(3.6)	101,853,216	99,943,510	1,909,706	1.9
34	BURNED:								
35	UNITS (TONS)	552,925	630,940	(78,015)	(12.4)	1,698,643	1,951,811	(253,168)	(13.0)
36	UNIT COST ($/TON)	44.15	47.44	(3.29)	(6.9)	44.43	47.07	(2.64)	(5.6)
37	AMOUNT ($)	24,411,907	29,930,110	(5,518,203)	(18.4)	75,473,736	91,876,242	(16,402,506)	(17.9)
38	ENDING INVENTORY:								
39	UNITS (TONS)	1,115,113	1,006,604	108,509	10.8	1,115,113	1,006,604	108,509	10.8
40	UNIT COST ($/TON)	42.27	46.87	(4.60)	(9.8)	42.27	46.87	(4.60)	(9.8)
41	AMOUNT ($)	47,132,484	47,178,809	(46,325)	(0.1)	47,132,484	47,178,809	(46,325)	(0.1)
42									
43	DAYS SUPPLY:	50	50	0	0.0	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER, 1998

	OTHER		CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	7,112
LUBE OIL PURCHASES	0
TOTAL	7,112

(2)RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(5,961)	(92,575)
OTHER USAGE	(2,100)	(36,413)
TOTAL	(8,061)	(128,988)

(3)RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
PROPANE IGNITION	7,191
IGNITION	85,463
FUEL ANALYSIS	54,695
AERIAL SURVEY ADJ.	84,537
ADDITIVES	149,104
TOTAL	380,990

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	158,506.0	0.0	158,506.0	1.507	1.986	2,389,100.00	3,147,700.00	606,880.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,662.0	0.0	5,662.0	1.521	1.521	86,100.00	86,100.00	
VARIOUS	SEPARATED	SCH. -D	31,129.0	0.0	31,129.0	1.539	1.809	479,000.00	563,000.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	1,234.0	0.0	1,234.0	2.374	3.314	29,300.00	40,900.00	
LAKELAND/FMPA		SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDICTIONAL	SCH. -J	7,396.0	0.0	7,396.0	1.677	1.677	124,000.00	124,000.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	203,927.0	0.0	203,927.0	1.524	1.943	3,107,500.00	3,961,700.00	606,880.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(201,300.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						606,880.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	203,927.0	0.0	203,927.0	1.723	1.943	3,513,080.00	3,961,700.00	606,880.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	587.0	0.0	587.0	1.800	2.094	10,566.57	12,289.00	1,377.94
FLA. PWR. & LIGHT		ECON.-C	100.0	0.0	100.0	1.862	2.243	1,862.00	2,242.50	304.40
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	55.0	0.0	55.0	1.790	2.289	984.36	1,259.02	219.73
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	142.0	0.0	142.0	1.737	2.221	2,467.20	3,154.51	549.85
CITY OF NEW SMYRNA BCH.		ECON.-C	4.0	0.0	4.0	1.789	3.269	71.56	130.75	47.35
ORLANDO UTIL. COMM.		ECON.-C	2,414.0	0.0	2,414.0	1.738	1.971	41,959.83	47,587.06	4,501.78
SEMINOLE ELECTRIC CO-OP		ECON.-C	965.0	0.0	965.0	1.677	2.112	16,187.53	20,383.97	3,357.15
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	28.0	0.0	28.0	1.698	1.942	475.40	543.71	54.65
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	5,186.0	0.0	5,186.0	1.675	1.838	86,861.12	95,325.18	6,771.25
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	76.0	0.0	76.0	1.760	2.729	1,337.66	2,074.11	589.16
NP ENERGY INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TENNESSEE VALLEY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA-E	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	9,150.0	0.0	9,150.0	1.715	1.861	156,915.14	170,306.95	
REEDY CREEK	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.342	1.610	199,689.60	239,568.00	
WAUCHULA	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.342	1.610	49,922.40	59,892.00	
FT. MEADE	SEPAR.	SCH. -D	3,191.0	0.0	3,191.0	1.342	1.610	42,823.22	51,375.10	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	4,804.0	0.0	4,804.0	2.531	3.325	121,589.24	159,733.00	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	1,414.0	1.4	1,412.6	1.652	1.652	23,329.74	23,329.74	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	574.0	0.0	574.0	1.532	1.532	8,795.89	8,795.89	
FLA. PWR. CORP.	JURISD.	SCH. -J	383.0	0.0	383.0	1.764	1.764	6,755.17	6,755.17	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FMPA	SCH. -D	70,920.0	70,920.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	22.0	0.0	22.0	2.239	2.462	492.47	541.66	39.35 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	10.0	0.0	10.0	1.889	2.012	188.90	201.18	9.82 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	54.0	0.0	54.0	2.083	2.355	1,124.86	1,271.59	117.38 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	717.0	0.0	717.0	2.154	2.303	15,444.18	16,515.52	857.07 *
HARDEE PWR. PARTNERS TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ENGY. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TVA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
ADJUSTMENTS TO NOV. 1998									
HARDEE POWER PARTNERS SEPAR.	CONTRACT	(780.0)	0.0	(780.0)	2.444	3.108	(19,063.20)	(24,242.40)	
HARDEE POWER PARTNERS SEPAR.	CONTRACT	780.0	0.0	780.0	2.531	3.325	19,741.80	25,935.00	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH.-D	(9,360.0)	0.0	(9,360.0)	1.689	1.835	(158,084.30)	(171,783.46)	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH.-D	9,360.0	0.0	9,360.0	1.688	1.834	157,954.14	171,653.30	
SUB-TOTAL ECONOMY POWER SALES		10,360.0	0.0	10,360.0	1.738	1.964	180,023.64	203,519.76	18,796.88
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		30,941.0	0.0	30,941.0	1.452	1.684	449,220.20	521,011.89	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		1,988.0	1.4	1,986.6	1.617	1.617	32,125.63	32,125.63	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		383.0	0.0	383.0	1.764	1.764	6,755.17	6,755.17	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		4,804.0	0.0	4,804.0	2.545	3.360	122,267.84	161,425.60	
SUB-TOTAL OTHER SCH. D POWER SALES		70,920.0	70,920.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	119,396.0	70,921.4	48,474.6	1.631	1.908	790,392.48	924,838.05	18,796.88
LESS VARIABLE O & M COSTS	-						(15,960.19)		
LESS VARIABLE O & M COSTS - HARDEE	-						(112.42)		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(18,790.04)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						18,796.88		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	119,396.0	70,921.4	48,474.6	1.597	1.908	774,326.71	924,838.05	18,796.88
CURRENT MONTH:									
DIFFERENCE	-	(84,531.0)	70,921.4	(155,452.4)	(0.126)	(0.035)	(2,738,753.29)	(3,036,861.95)	(588,083.12)
DIFFERENCE %	-	(41.5)	0.0	(76.2)	(7.3)	(1.8)	(78.0)	(76.7)	(96.9)
PERIOD TO DATE:									
ACTUAL	-	384,561.0	195,716.6	188,844.4	1.626	1.920	3,071,182.32	3,625,714.61	102,281.52
ESTIMATED	-	626,152.0	0.0	626,152.0	1.798	2.040	11,255,620.00	12,773,500.00	2,071,520.00
DIFFERENCE	-	(241,591.0)	195,716.6	(437,307.6)	(0.172)	(0.120)	(8,184,437.68)	(9,147,785.39)	(1,969,238.48)
DIFFERENCE %	-	(38.6)	0.0	(69.8)	(9.6)	(5.9)	(72.7)	(71.6)	(95.1)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $116.19 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	259.0	0.0	166.0	93.0	5.161	5.161	4,800.00
HARDEE POWER PARTNERS	IPP	18,959.0	0.0	0.0	18,959.0	4.394	4.394	833,000.00
VARIOUS	OTHER	58,688.0	58,688.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	77,906.0	58,688.0	166.0	19,052.0	4.397	4.397	837,800.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	29,329.0	0.0	0.0	29,329.0	3.147	3.147	922,933.22
HARDEE PWR. PART.-OTHERS	IPP	803.0	0.0	0.0	803.0	2.102	2.116	16,882.63
FLA. POWER CORP.	SCH.-JC	15,314.0	0.0	0.0	15,314.0	2.279	2.279	349,049.75
FLA. POWER & LIGHT	SCH.-JA	238.0	0.0	233.2	4.8	4.700	4.700	225.60
FLA. POWER & LIGHT	SCH.-JC	10,478.0	0.0	0.0	10,478.0	2.799	2.799	293,237.25
CITY OF LAKELAND	SCH.-JC	2,098.0	0.0	0.0	2,098.0	2.397	2.397	50,295.10
ORLANDO UTIL. COMM.	SCH.-JC	2,912.0	0.0	0.0	2,912.0	3.181	3.181	92,640.00
THE ENERGY AUTHORITY	SCH.-JC	807.0	0.0	0.0	807.0	2.629	2.629	21,216.00
PECO	OTHER	39,215.0	39,215.0	0.0	0.0	0.000	0.000	0.00
FLORIDA POWER CORP.	OTHER	31,705.0	31,705.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS								
HARDEE PWR.PART.-NATIVE 11/98	IPP	(99,324.0)	0.0	0.0	(99,324.0)	2.274	2.274	(2,258,682.29)
HARDEE PWR.PART.-NATIVE 11/98	IPP	99,324.0	0.0	0.0	99,324.0	2.248	2.248	2,232,645.40
THE ENERGY AUTHORITY 10/98	SCH.-JC	(2,103.0)	0.0	0.0	(2,103.0)	3.694	3.694	(77,678.12)
THE ENERGY AUTHORITY 10/98	SCH.-JC	2,103.0	0.0	0.0	2,103.0	3.599	3.599	75,696.12
TOTAL		132,899.0	70,920.0	233.2	61,745.8	2.783	2.783	1,718,460.66
CURRENT MONTH:								
DIFFERENCE	-	54,993.0	12,232.0	67.2	42,693.8	(1.614)	(1.614)	880,660.66
DIFFERENCE %	-	70.6	20.8	40.5	224.1	(36.7)	(36.7)	105.1
PERIOD TO DATE:								
ACTUAL	-	497,641.0	195,445.0	10,158.1	292,037.9	2.424	2.424	7,078,917.75
ESTIMATED	-	242,095.0	0.0	1,768.0	240,327.0	1.035	1.035	2,488,500.00
DIFFERENCE	-	255,546.0	195,445.0	8,390.1	51,710.9	1.389	1.389	4,590,417.75
DIFFERENCE %	-	105.6	0.0	474.6	21.5	134.2	134.2	184.5

SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	38,569.0	0.0	0.0	38,569.0	1.471	1.471	567,300.00
TOTAL	-	38,569.0	0.0	0.0	38,569.0	1.471	1.471	567,300.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	385.0	0.0	0.0	385.0	2.092	2.092	8,052.65
McKAY BAY REFUSE	COGEN.	9,395.0	0.0	0.0	9,395.0	1.788	1.788	167,991.73
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	2,103.0	0.0	0.0	2,103.0	1.951	1.951	41,038.77
HILLSBOROUGH COUNTY	COGEN.	19,807.0	0.0	0.0	19,807.0	1.796	1.796	355,790.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	229.0	0.0	0.0	229.0	2.170	2.170	4,969.33
FARMLAND HYDRO LP	COGEN.	690.0	0.0	0.0	690.0	1.995	1.995	13,763.00
IMC-AGRICO-S. PIERCE	COGEN.	173.0	0.0	0.0	173.0	1.893	1.893	3,274.29
AUBURNDALE POWER PARTNERS	COGEN.	84.0	0.0	0.0	84.0	1.619	1.619	1,359.82
ORANGE COGENERATION L.P.	COGEN.	4,949.0	0.0	0.0	4,949.0	1.766	1.766	87,418.29
AS AVAILABLE ASSIGNMENT	*COGEN.*	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR DECEMBER, 1998	-	37,815.0	0.0	0.0	37,815.0	1.808	1.808	683,657.88
ADJUSTMENTS FOR OCT., 1998								
IMC-AGRICO-NICHOLS	COGEN.	(388.0)	0.0	0.0	(388.0)	2.473	2.473	(9,594.04)
		388.0	0.0	0.0	388.0	2.474	2.474	9,597.21
McKAY BAY REFUSE	COGEN.	(10,469.0)	0.0	0.0	(10,469.0)	1.840	1.840	(192,635.57)
		10,469.0	0.0	0.0	10,469.0	1.996	1.996	209,006.07
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(20,352.0)	0.0	0.0	(20,352.0)	1.855	1.855	(377,438.42)
		20,352.0	0.0	0.0	20,352.0	2.021	2.021	411,334.76
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.	(285.0)	0.0	0.0	(285.0)	2.796	2.796	(7,969.13)
		285.0	0.0	0.0	285.0	2.801	2.801	7,981.44
FARMLAND INDUSTRIES	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.	(515.0)	0.0	0.0	(515.0)	2.414	2.414	(12,432.52)
		515.0	0.0	0.0	515.0	2.414	2.414	12,431.49
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(3,542.0)	0.0	0.0	(3,542.0)	1.778	1.778	(62,967.17)
		3,542.0	0.0	0.0	3,542.0	1.989	1.989	70,453.17
AS AVAILABLE ASSIGNMENT	COGEN.	102.0	0.0	0.0	102.0	4.752	4.752	4,847.02
		(102.0)	0.0	0.0	(102.0)	4.770	4.770	(4,865.02)
SUB-TOTAL FOR OCT., 1998	-	0.0	0.0	0.0	0.0	0.000	0.000	57,749.29
GRAND TOTAL		37,815.0	0.0	0.0	37,815.0	1.961	1.961	741,407.17
CURRENT MONTH:								
DIFFERENCE	-	(754.0)	0.0	0.0	(754.0)	0.490	0.490	174,107.17
DIFFERENCE %	-	(2.0)	0.0	0.0	(2.0)	33.3	33.3	30.7
PERIOD TO DATE:								
ACTUAL		113,147.0	0.0	137.0	113,010.0	1.937	1.937	2,189,387.43
ESTIMATED		115,526.0	0.0	0.0	115,526.0	1.830	1.830	2,114,200.00
DIFFERENCE	-	(2,379.0)	0.0	137.0	(2,516.0)	0.107	0.107	75,187.43
DIFFERENCE %	-	(2.1)	0.0	0.0	(2.2)	5.8	5.8	3.6

SCHEDULE A9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF DECEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	301.0	2.458	7,400.00	3.854	11,600.00	4,200.00
TOTAL	-	301.0	2.458	7,400.00	3.854	11,600.00	4,200.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ADJ. TO PRIOR MONTHS							
FLA. PWR. & LIGHT 11/98	ECON.-C	(98.0)	4.236	(4,150.89)	4.236	(4,151.59)	(0.70)
FLA. PWR. & LIGHT 11/98	ECON.-C	98.0	4.241	4,156.09	4.236	4,151.59	(4.50)
TRANSMISSION REFUND 11/97 TO 9/98				(1,724.88)		(1,724.88)	0.00
TOTAL	-	0.0	0.000	(1,719.68)	0.000	(1,724.88)	(5.20)
CURRENT MONTH:							
DIFFERENCE	-	(301.0)	(2.458)	(9,119.68)	(3.854)	(13,324.88)	(4,205.20)
DIFFERENCE %	-	(100.0)	(100.0)	(123.2)	(100.0)	(114.9)	(100.1)
PERIOD TO DATE:							
ACTUAL		2,346.0	3.416	80,142.45	3.879	91,002.03	10,859.58
ESTIMATED		2,053.0	2.986	61,300.00	3.999	82,100.00	20,800.00
DIFFERENCE	-	293.0	0.430	18,842.45	(0.120)	8,902.03	(9,940.42)
DIFFERENCE %	-	14.3	14.4	30.7	(3.0)	10.8	(47.8)

COMMISSION SCHEDULES A6 - A9

NINE MONTH TOTALS

APRIL 1998 - DECEMBER 1998

TAMPA ELECTRIC COMPANY
POWER SOLD
FOR THE MONTHS OF APRIL, 1998 THRU DECEMBER, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:									
VARIOUS	ECON.	975,165.0	0.0	975,165.0	1.598	2.148	15,587,000.00	20,944,700.00	4,286,160.00
VARIOUS JURISDICTIONAL	SCH. -D	47,732.0	0.0	47,732.0	1.675	1.675	799,300.00	799,300.00	
VARIOUS SEPARATED	SCH. -D	291,221.0	0.0	291,221.0	1.490	1.742	4,338,800.00	5,074,100.00	
VARIOUS	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS SEPARATED	CONTRACT	122,578.0	0.0	122,578.0	2.348	3.171	2,878,100.00	3,886,400.00	
LAKELAND/FMPA	*SCH. -D*	373,320.0	0.0	373,320.0	1.487	1.563	5,552,500.00	5,835,000.00	
VARIOUS JURISDICTIONAL	SCH. -J	37,302.0	0.0	37,302.0	2.205	2.205	822,500.00	822,500.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	1,847,318.0	0.0	1,847,318.0	1.623	2.022	29,978,200.00	37,362,000.00	4,286,160.00
LESS TRANSMISSION COSTS	-						0.00		
LESS VARIABLE O & M COSTS	-						(1,238,400.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						4,286,160.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	1,847,318.0	0.0	1,847,318.0	1.788	2.022	33,025,960.00	37,362,000.00	4,286,160.00
ACTUAL:									
FLA. PWR. CORP.	ECON.-C	54,738.0	0.0	54,738.0	1.968	2.800	1,077,384.86	1,532,537.44	364,122.06
FLA. PWR. & LIGHT	ECON.-C	70,653.0	0.0	70,653.0	1.663	1.950	1,174,633.46	1,377,510.25	162,301.46
CITY OF LAKELAND	ECON.-C	6,630.0	0.0	6,630.0	1.656	2.245	109,780.67	148,876.40	31,276.58
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	2,363.0	0.0	2,363.0	1.686	2.545	39,842.75	60,129.99	16,229.78
CITY OF HOMESTEAD	ECON.-C	1,190.0	0.0	1,190.0	1.734	2.180	20,637.48	25,937.65	4,240.13
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	2,135.0	0.0	2,135.0	1.814	2.978	38,738.41	63,577.28	19,871.10
CITY OF NEW SMYRNA BCH.	ECON.-C	266.0	0.0	266.0	2.135	4.512	5,677.99	12,001.42	5,058.74
ORLANDO UTIL. COMM.	ECON.-C	52,892.0	0.0	52,892.0	1.631	1.900	862,429.38	1,004,725.05	113,836.53
SEMINOLE ELECTRIC CO-OP	ECON.-C	21,450.0	0.0	21,450.0	1.708	2.174	366,387.59	466,356.84	79,975.40
CITY OF ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE	ECON.-C	146.0	0.0	146.0	1.993	4.457	2,910.46	6,507.38	2,877.54
CITY OF VERO BEACH	*ECON.-C*	*0.0*	*0.0*	*0.0*	*0.000*	*0.000*	*0.00*	*0.00*	*0.00*
FMPA	ECON.-C	907.0	0.0	907.0	1.628	1.945	14,765.92	17,643.02	2,301.68
KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK	ECON.-C	106,073.0	0.0	106,073.0	1.642	1.999	1,742,030.57	2,120,851.38	303,056.65
SONAT	ECON.-C	491.0	0.0	491.0	1.872	7.701	9,189.19	37,813.50	22,899.45
THE ENERGY AUTHORITY	ECON.-C	2,234.0	0.0	2,234.0	3.144	6.146	70,234.07	137,312.49	53,662.72
NP ENERGY INC.	ECON.-C	2,250.0	0.0	2,250.0	1.528	2.121	34,368.00	47,725.00	10,669.60
KOCH	ECON.-C	8,255.0	0.0	8,255.0	2.780	29.035	229,479.62	2,396,843.36	1,733,890.99
TENNESSEE VALLEY AUTHORITY	ECON.-C	9,196.0	0.0	9,196.0	3.129	24.719	287,786.96	2,273,167.24	1,588,304.22
FLA. PWR. & LIGHT	SEPAR. SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR. SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR. SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR. SCH. -D	95,563.0	0.0	95,563.0	1.682	1.829	1,607,607.77	1,748,112.85	
REEDY CREEK	SEPAR. SCH. -D	131,980.0	0.0	131,980.0	1.362	1.634	1,797,313.40	2,156,836.80	
WAUCHULA	SEPAR. SCH. -D	33,000.0	0.0	33,000.0	1.362	1.634	449,396.40	539,290.80	
FORT MEADE	SEPAR. SCH. -D	31,377.0	0.0	31,377.0	1.363	1.635	427,547.74	513,076.30	
CITY OF ST. CLOUD	SEPAR. SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	CONTRACT SCH. -D	280,964.0	0.0	280,964.0	2.077	2.718	5,835,485.00	7,636,993.64	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD. SCH. -D	36,283.0	2,673.3	33,609.7	1.880	1.880	631,814.00	631,814.00	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD. SCH. -D	6,528.0	0.0	6,528.0	1.557	1.557	101,621.92	101,621.92	
FLA. PWR. CORP.	JURISD. SCH. -J	492.0	0.0	492.0	1.378	1.378	6,781.64	6,781.64	
FLA. PWR. & LIGHT	JURISD. SCH. -J	1,624.0	0.0	1,624.0	4.443	4.443	72,153.36	72,153.36	
CITY OF HOMESTEAD	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	(39.53)	(39.53)	
KISSIMMEE ELEC. UTIL.	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	(895.85)	(895.85)	
ORLANDO UTIL. COMM.	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	(163.20)	(163.20)	
REEDY CREEK	*JURISD. SCH. -J*	*45,895.0*	*0.0*	*45,895.0*	*2.263*	*2.263*	*1,038,548.50*	*1,038,548.50*	
SEMINOLE ELECTRIC CO-OP	JURISD. SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD. SCH. -J	17,670.0	0.0	17,670.0	2.297	2.297	405,954.68	405,954.68	

TAMPA ELECTRIC COMPANY
POWER SOLD
FOR THE MONTHS OF APRIL, 1998 THRU DECEMBER, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00		
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	(161.20)	(161.20)		
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	(66.95)	(66.95)		
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	(100.98)	(100.98)		
CITY OF GAINESVILLE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	(527.29)	(527.29)		
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	(33.10)	(33.10)		
FMPA		SCH. -D	568,680.0	552,016.0	16,664.0	1.776	1.753	296,016.79	292,154.68		
CITY OF LAKELAND		SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	(1,864.01)		
FLA. PWR. CORP.		C.T. -A	80.0	0.0	80.0	4.878	4.878	3,902.05	3,902.05		
HARDEE PWR. PARTNERS TO FPC		ECON.-C	14,822.0	0.0	14,822.0	2.333	2.912	345,796.04	431,679.78	68,707.00	*
HARDEE PWR. PARTNERS TO FP&L		ECON.-C	5,499.0	0.0	5,499.0	3.116	3.635	171,328.74	199,889.00	22,848.22	*
HARDEE PWR. PARTNERS TO REEDY CREEK		ECON.-C	1,000.0	0.0	1,000.0	1.991	2.331	19,907.12	23,314.89	2,726.21	*
HARDEE PWR. PARTNERS TO GAINESVILLE		ECON.-C	569.0	0.0	569.0	2.081	2.584	11,839.41	14,703.63	2,291.38	*
HARDEE PWR. PARTNERS TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO KISSIMMEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH		ECON.-C	69.0	0.0	69.0	2.467	3.537	1,702.10	2,440.67	590.85	*
HARDEE PWR. PARTNERS TO ORLANDO		ECON.-C	1,101.0	0.0	1,101.0	2.218	2.484	24,415.96	27,349.06	2,346.47	*
HARDEE PWR. PARTNERS TO STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	40.24	32.19	*
HARDEE PWR. PARTNERS TO HOMESTEAD		ECON.-C	66.0	0.0	66.0	1.829	2.174	1,207.11	1,434.66	182.04	*
HARDEE PWR. PARTNERS TO SEMINOLE		ECON.-C	3,996.0	0.0	3,996.0	2.733	3.058	109,222.44	122,185.77	10,370.66	*
HARDEE PWR. PARTNERS TO FT. PIERCE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO TALLAHASSEE		ECON.-C	76.0	0.0	76.0	1.942	2.565	1,476.20	1,964.23	390.42	*
HARDEE PWR. PARTNERS TO LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO LAKE WORTH		ECON.-C	406.0	0.0	406.0	2.223	2.994	9,026.02	12,157.56	2,505.24	*
HARDEE PWR. PARTNERS TO KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO THE ENGY. AUTH.		ECON.-C	44.0	0.0	44.0	2.465	3.357	1,084.60	1,477.13	314.02	*
HARDEE PWR. PARTNERS TO KOCH		ECON.-C	1,982.0	0.0	1,982.0	4.479	24.463	88,768.02	484,853.21	316,868.15	*
HARDEE PWR. PARTNERS TO TENNESSEE VALLEY		ECON.-C	1,208.0	0.0	1,208.0	3.812	12.943	46,043.36	156,349.48	88,244.89	*
HARDEE PWR. PARTNERS TO SONAT		ECON.-C	594.0	0.0	594.0	3.612	4.178	21,457.56	24,817.66	2,688.08	*
HARDEE PWR. PARTNERS TO SEMINOLE		SCH. -G	75.0	0.0	75.0	3.879	3.879	2,909.27	2,909.27		
HARDEE PWR. PARTNERS TO FP&L		SCH. -J	2,289.0	0.0	2,289.0	2.455	2.455	56,185.50	56,185.50		
SUB-TOTAL ECONOMY POWER SALES			373,301.0	0.0	373,301.0	1.859	3.545	6,939,572.06	13,234,172.66	5,035,680.45	
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.			291,920.0	0.0	291,920.0	1.467	1.698	4,281,865.31	4,957,316.75		
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			42,811.0	2,673.3	40,137.7	1.827	1.827	733,435.92	733,435.92		
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.			67,970.0	0.0	67,970.0	2.321	2.321	1,577,668.68	1,577,668.68		
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.			75.0	0.0	75.0	3.835	3.835	2,876.17	2,876.17		
SUB-TOTAL HARDEE POWER PART.CONTRACT SALES-SEPAR.			280,964.0	0.0	280,964.0	2.077	2.718	5,835,485.00	7,636,993.64		
SUB-TOTAL OTHER POWER SALES			568,760.0	552,016.0	16,744.0	1.791	1.757	299,918.84	294,192.72		
TOTAL INCLUDING VARIABLE O & M COSTS	-		1,625,801.0	554,689.3	1,071,111.7	1.836	2.655	19,670,821.98	28,436,656.54	5,035,680.45	
LESS VARIABLE O & M COSTS	-							(570,921.23)			
LESS VARIABLE O & M COSTS - HARDEE	-							(3,617.71)			
LESS TRANSMISSION COSTS SCH.-D (SEP.)								(166,459.92)			
LESS TRANSMISSION COSTS SCH.-D (OTHER)								(31,859.96)			
PLUS 80% OF ECON. ENERGY SALES PROFITS	-							5,035,680.45			
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-		**1,625,801.0**	**554,689.3**	**1,071,111.7**	**2.234**	**2.655**	**23,933,643.61**	**28,436,656.54**	**5,035,680.45**	
DIFFERENCE	-		(221,517.0)	554,689.3	(776,206.3)	0.6	0.6	(6,044,556.4)	(8,925,343.5)	749,520.5	
DIFFERENCE %	-		(12.0)	0.0	(42.0)	37.6	31.3	(20.2)	(23.9)	17.5	

* ONLY TEC 40% REFLECTED HERE. SEC 60% OR $930,616.03 HAS BEEN EXCLUDED.

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
FOR THE PERIOD APRIL, 1998 THRU DECEMBER, 1998

SCHEDULE A7

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	31,969.0	0.0	20,487.0	11,482.0	5.161	5.161	592,600.00
HARDEE POWER PARTNERS	IPP	390,707.0	0.0	0.0	390,707.0	3.153	3.153	12,318,400.00
ST. CLOUD	PEAKING	174,171.0	174,171.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	596,847.0	174,171.0	20,487.0	402,189.0	3.210	3.210	12,911,000.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	659,161.0	0.0	0.0	659,161.0	2.515	2.515	16,575,845.06
HARDEE PWR. PART.-FOR OTHERS	IPP	33,796.0	0.0	0.0	33,796.0	2.636	2.649	890,791.08
FLA. POWER CORP.	SCH. -Ja	28,719.0	0.0	22,660.7	6,058.3	6.043	6.043	366,076.22
FLA. POWER CORP.	SCH. -Jc	76,620.0	0.0	0.0	76,620.0	2.849	2.849	2,182,745.76
FLA. PWR. & LIGHT	SCH. -Ja	42,880.0	0.0	30,758.9	12,121.1	5.830	5.830	706,709.24
FLA. PWR. & LIGHT	SCH. -Jc	67,521.0	0.0	0.0	67,521.0	3.288	3.288	2,219,899.09
ORLANDO UTIL. COMM.	SCH. -Ja	34,986.0	0.0	19,482.9	15,503.1	7.145	7.145	1,107,652.75
ORLANDO UTIL. COMM.	SCH. -Jc	39,143.0	0.0	0.0	39,143.0	3.425	3.425	1,340,597.02
CITY OF LAKELAND	SCH. -Ja	5,982.0	0.0	3,994.3	1,987.7	4.643	4.643	92,291.90
CITY OF LAKELAND	SCH. -Jc	16,660.0	0.0	0.0	16,660.0	3.120	3.120	519,821.85
KISSIMMEE ELEC. UTIL.	SCH. -Ja	713.0	0.0	713.0	0.0	0.000	0.000	0.00
KISSIMMEE ELEC. UTIL.	SCH. -Jc	937.0	0.0	0.0	937.0	3.687	3.687	34,550.00
THE ENERGY AUTH.	SCH. -Ja	6,614.0	0.0	4,638.3	1,975.7	5.442	5.442	107,521.89
THE ENERGY AUTH.	SCH. -Jc	13,770.0	0.0	3,213.7	10,556.3	5.608	5.608	592,032.53
REEDY CREEK	SCH. -Ja	185.0	0.0	185.0	0.0	0.000	0.000	0.00
REEDY CREEK	SCH. -Jc	50.0	0.0	0.0	50.0	8.500	8.500	4,250.00
PECO	SCH. -Ja	2,145.0	0.0	1,258.5	886.5	4.487	4.487	39,780.88
PECO	SCH. -Jc	2,378.0	0.0	0.0	2,378.0	3.302	3.302	78,528.00
KOCK ENERGY TRAD.	SCH. -Ja	2,159.0	0.0	1,366.0	793.0	8.002	8.002	63,456.14
KOCK ENERGY TRAD.	SCH. -Jc	766.0	0.0	0.0	766.0	4.027	4.027	30,847.29
SEMINOLE ELEC. CO-OP	SCH. -Ja	2,434.0	0.0	2,320.0	114.0	5.500	5.500	6,270.31
SEMINOLE ELEC. CO-OP	SCH. -Jc	156.0	0.0	0.0	156.0	5.332	5.332	8,318.54
OGLETHORPE	SCH. -Jc	1,517.0	0.0	0.0	1,517.0	5.108	5.108	77,481.76
LAKE WORTH UTILITIES	SCH. -Ja	596.0	0.0	596.0	0.0	0.000	0.000	0.00
LAKE WORTH UTILITIES	SCH. -Jc	160.0	0.0	133.0	27.0	9.411	9.411	2,541.04
TALLAHASSEE	SCH. -Ja	244.0	0.0	244.0	0.0	0.000	0.000	0.00
VIRGINIA ELECTRIC POWER	SCH. -Ja	1,200.0	0.0	1,200.0	0.0	0.000	0.000	0.00
CITY OF GAINESVILLE	SCH. -Ja	2,896.0	0.0	1,486.6	1,409.4	4.799	4.799	67,636.24
CITY OF GAINESVILLE	SCH. -Jc	922.0	0.0	0.0	922.0	4.744	4.744	43,742.35
SONAT	SCH. -Jc	240.0	0.0	124.0	116.0	10.000	10.000	11,600.00
PECO	OTHER	347,875.0	347,875.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	204,141.0	204,141.0	0.0	0.0	0.000	0.000	0.00
TOTAL		1,597,566.0	552,016.0	94,374.9	951,175.1	2.857	2.862	27,170,986.94
DIFFERENCE	-	1,000,719.0	377,845.0	73,887.9	548,986.1	(0.353)	(0.348)	14,259,986.94
DIFFERENCE %	-	167.7	216.9	360.7	136.5	(11.0)	(10.8)	110.4

SCHEDULE A8

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE PERIOD APRIL, 1998 THRU DECEMBER, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	CENTS/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	353,275.0	0.0	0.0	353,275.0	2.143	2.143	7,571,400.00
TOTAL	-	353,275.0	0.0	0.0	353,275.0	2.143	2.143	7,571,400.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	7,722.0	0.0	0.0	7,722.0	3.080	3.080	237,816.01
McKAY BAY REFUSE	COGEN.	91,018.0	0.0	0.0	91,018.0	1.829	1.829	1,664,958.92
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	4,051.0	0.0	0.0	4,051.0	2.381	2.381	96,470.80
HILLSBOROUGH COUNTY	COGEN.	172,235.0	0.0	0.0	172,235.0	1.835	1.835	3,160,645.06
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	3,682.0	0.0	0.0	3,682.0	3.535	3.535	130,166.20
FARMLAND HYDRO LP	COGEN.	1,574.0	0.0	0.0	1,574.0	3.005	3.005	47,295.41
IMC-AGRICO-S. PIERCE	COGEN.	5,480.0	0.0	0.0	5,480.0	3.411	3.411	186,917.54
AUBURNDALE PWR.PARTNERS	COGEN.	3,284.0	0.0	0.0	3,284.0	2.333	2.333	76,603.21
ORANGE COGEN L.P.	COGEN.	57,427.0	0.0	0.0	57,427.0	1.828	1.828	1,049,903.83
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	3,019.7	(3,019.7)	8.689	8.689	(262,385.46)
1997 LINE LOSS ADJUSTMENT								(2,810.37)
TOTAL	-	346,473.0	0.0	3,019.7	343,453.3	1.859	1.859	6,385,581.15
DIFFERENCE	-	(6,802.0)	0.0	3,019.7	(9,821.7)	(0.284)	(0.284)	(1,185,818.85)
DIFFERENCE %	-	(1.9)	0.0	0.0	(2.8)	(13.3)	(13.3)	(15.7)

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
FOR THE PERIOD APRIL, 1998 THRU DECEMBER, 1998

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	COST IF GENERATED (A) cents/KWH	(B) $	FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	35,317.0	4.255	1,502,800.00	5.033	1,777,400.00	274,600.00
TOTAL	-	35,317.0	4.255	1,502,800.00	5.033	1,777,400.00	274,600.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	651.0	2.392	15,568.88	2.997	19,512.25	3,943.37
FLA. PWR. & LIGHT	ECON.-C	3,314.0	2.810	93,139.41	3.188	105,654.58	12,515.17
CITY OF LAKELAND	ECON.-C	25.0	2.808	702.00	3.141	785.25	83.25
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	295.0	3.497	10,317.50	4.215	12,434.44	2,116.94
CITY OF HOMESTEAD	ECON.-C	63.0	3.965	2,497.68	4.321	2,722.11	224.43
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	271.0	3.416	9,257.35	3.730	10,108.88	851.53
ORLANDO UTIL. COMM.	ECON.-C	1,845.0	3.119	57,538.51	3.700	68,261.90	10,723.39
SEMINOLE ELECTRIC CO-OP.	ECON.-C	164.0	3.628	5,950.45	3.139	5,148.53	(801.92)
TALLAHASSEE	ECON.-C	104.0	3.313	3,445.91	4.000	4,159.98	714.07
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	53.0	3.239	1,716.45	3.729	1,976.40	259.95
PECO	ECON.-C	1,296.0	3.057	39,620.47	4.082	52,902.93	13,282.46
THE ENERGY AUTHORITY	ECON.-C	697.0	3.545	24,708.75	4.660	32,478.19	7,769.44
TRANSMISSION REFUND 11/97 THRU 9/98				(1,724.88)		(1,724.88)	0.00
TOTAL	-	8,778.0	2.993	262,738.48	3.582	314,420.56	51,682.08
DIFFERENCE	-	(26,539.0)	(1.262)	(1,240,061.52)	(1.451)	(1,462,979.44)	(222,917.92)
DIFFERENCE %	-	(75.1)	(29.7)	(82.5)	(28.8)	(82.3)	(81.2)

COMMISSION SCHEDULES A1 - A9

NOVEMBER 1998

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998

	$				KWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	23,111,738	30,413,718	(7,301,980)	(24.0)	1,144,157	1,412,984	(268,827)	(19.0)	2.01998	2.15245	(0.13247)	(6.2)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,528)	(3,000)	472	(15.7)	1,144,157 (a)	1,412,984 (a)	(268,827)	(19.0)	(0.00022)	(0.00021)	(0.00001)	4.8
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,144,157 (a)	1,412,984 (a)	(268,827)	(19.0)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,144,157 (a)	1,412,984 (a)	(268,827)	(19.0)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	23,109,210	30,410,718	(7,301,508)	(24.0)	1,144,157	1,412,984	(268,827)	(19.0)	2.01976	2.15223	(0.13247)	(6.2)
6. Fuel Cost of Purchased Power - Firm (A7)	3,256,486	932,000	2,324,486	249.4	132,985	28,502	104,483	366.6	2.44876	3.26995	(0.82119)	(25.1)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	5,258	7,000	(1,742)	(24.9)	166	262	(96)	(36.6)	3.16747	2.67176	0.49571	18.6
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	750,352	853,700	(103,348)	(12.1)	38,956	38,045	911	2.4	1.92615	2.24392	(0.31777)	(14.2)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	4,012,096	1,792,700	2,219,396	123.8	172,107	66,809	105,298	157.6	2.33116	2.68332	(0.35216)	(13.1)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,316,264	1,479,793	(163,529)	(11.1)				
14. Fuel Cost of Economy Sales (A6)	226,543	2,581,700	(2,355,157)	(91.2)	14,124	174,980	(160,856)	(91.9)	1.60396	1.47543	0.12853	8.7
15. Gain on Economy Sales - 80% (A6)	29,952	766,560	(736,608)	(96.1)	14,124 (a)	174,980 (a)	(160,856)	(91.9)	0.21206	0.43808	(0.22602)	(51.6)
16. Fuel Cost of Sch. D Separ. Sales (A6)	423,179	461,000	(37,821)	(8.2)	30,406	29,932	474	1.6	1.39176	1.54016	(0.14840)	(9.6)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	47,114	88,000	(40,886)	(46.5)	4,089	5,625	(1,536)	(27.3)	1.15221	1.56444	(0.41223)	(26.4)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	56,831	12,500	44,331	354.6	2,345	766	1,579	206.1	2.42350	1.63185	0.79165	48.5
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	103,295	121,600	(18,305)	(15.1)	780	5,143	(4,363)	(84.8)	13.24295	2.36438	10.87857	460.1
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	886,914	4,031,360	(3,144,446)	(78.0)	51,744	216,446	(164,702)	(76.1)	1.71404	1.86252	(0.14848)	(8.0)
23. Net Inadvertant Interchange					(185)	0	(185)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					132	0	132	0.0				
25. Interchange and Wheeling Losses					2,140	3,300	(1,160)	(35.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	26,234,392	28,172,058	(1,937,666)	(6.9)	1,262,327	1,260,047	2,280	0.2	2.07826	2.23579	(0.15753)	(7.0)
27. Net Unbilled	(1,013,879)(a)	(502,158)(a)	(511,721)	101.9	(48,785)	(22,460)	(26,325)	117.2	(0.08032)	(0.03985)	(0.04047)	101.6
28. Company Use	79,784 (a)	76,017 (a)	3,767	5.0	3,839	3,400	439	12.9	0.00629	0.00625	0.00004	0.6
29. T & D Losses	800,525 (a)	1,397,436 (a)	(596,911)	(42.7)	38,519	62,503	(23,984)	(38.4)	0.06310	0.11486	(0.05176)	(45.1)
30. System KWH Sales	26,234,392	28,172,058	(1,937,666)	(6.9)	1,268,754	1,216,604	52,150	4.3	2.06773	2.31563	(0.24790)	(10.7)
31. Wholesale KWH Sales	(108,180)	(76,093)	(32,087)	42.2	(5,232)	(3,286)	(1,946)	59.2	2.06766	2.31567	(0.24801)	(10.7)
32. Jurisdictional KWH Sales	26,126,212	28,095,965	(1,969,753)	(7.0)	1,263,522	1,213,318	50,204	4.1	2.06773	2.31563	(0.24790)	(10.7)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	26,129,608	28,099,617	(1,970,009)	(7.0)	1,263,522	1,213,318	50,204	4.1	2.06800	2.31593	(0.24793)	(10.7)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	409,703	410,288	(585)	(0.1)	1,263,522	1,213,318	50,204	4.1	0.03243	0.03382	(0.00139)	(4.1)
36. Adjustment - Oil Below the Discharge Valve	0	0	0	0.0	1,263,522	1,213,318	50,204	4.1	0.00000	0.00000	0.00000	0.0
37. True-up *	(1,334,790)	(1,334,790)	0	0.0	1,263,522	1,213,318	50,204	4.1	(0.10564)	(0.11001)	0.00437	(4.0)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	25,204,521	27,175,115	(1,970,594)	(7.3)	1,263,522	1,213,318	50,204	4.1	1.99478	2.23974	(0.24496)	(10.9)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									1.99644	2.24160	(0.24516)	(10.9)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,263,522	1,213,318	50,204	4.1	(0.00480)	(0.00499)	0.00019	(3.8)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	25,143,930	27,114,524	(1,970,594)	(7.3)	1,263,522	1,213,318	50,204	4.1	1.99164	2.23661	(0.24497)	(11.0)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									1.992	2.237	(0.245)	(11.0)

* Based on Jurisdictional Sales (a) Included for informational purposes only

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: NOVEMBER, 1998

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	53,896,015	62,929,684	(9,033,669)	(14.4)	2,591,482	2,931,359	(339,877)	(11.6)	2.07974	2.14678	(0.06704)	(3.1)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,676)	(6,000)	1,324	(22.1)	2,591,482 (a)	2,931,359 (a)	(339,877)	(11.6)	(0.00018)	(0.00020)	0.00002	(10.0)
4b. Adjustments to Fuel Cost	0	0	0	0.0	2,591,482 (a)	2,931,359 (a)	(339,877)	(11.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	2,591,482 (a)	2,931,359 (a)	(339,877)	(11.6)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	53,891,339	62,923,684	(9,032,345)	(14.4)	2,591,482	2,931,359	(339,877)	(11.6)	2.07956	2.14657	(0.06701)	(3.1)
6. Fuel Cost of Purchased Power - Firm (A7)	5,360,457	1,650,700	3,709,757	224.7	230,292	47,104	183,188	388.9	2.32768	3.50437	(1.17669)	(33.6)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	80,137	53,900	26,237	48.7	2,346	1,752	594	33.9	3.41590	3.07648	0.33942	11.0
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,447,980	1,546,900	(98,920)	(6.4)	75,195	76,957	(1,762)	(2.3)	1.92563	2.01008	(0.08445)	(4.2)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	6,888,574	3,251,500	3,637,074	111.9	307,833	125,813	182,020	144.7	2.23776	2.58439	(0.34663)	(13.4)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					2,899,315	3,057,172	(157,857)	(5.2)				
14. Fuel Cost of Economy Sales (A6)	673,713	4,865,300	(4,191,587)	(86.2)	42,313	336,995	(294,682)	(87.4)	1.59221	1.44373	0.14848	10.3
15. Gain on Economy Sales - 80% (A6)	83,484	1,464,640	(1,381,156)	(94.3)	42,313	336,995 (a)	(294,682)	(87.4)	0.19730	0.43462	(0.23732)	(54.6)
16. Fuel Cost of Sch. D Separ. Sales (A6)	753,557	944,000	(190,443)	(20.2)	62,353	61,214	1,139	1.9	1.20853	1.54213	(0.33360)	(21.6)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	150,040	178,500	(28,460)	(15.9)	9,246	11,336	(2,090)	(18.4)	1.62276	1.57463	0.04813	3.1
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	56,831	17,600	39,231	222.9	2,345	1,082	1,263	116.7	2.42350	1.62662	0.79688	49.0
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	579,231	272,500	306,731	112.6	24,113	11,598	12,515	107.9	2.40215	2.34954	0.05261	2.2
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,296,856	7,742,540	(5,445,684)	(70.3)	140,370	422,225	(281,855)	(66.8)	1.63629	1.83375	(0.19746)	(10.8)
23. Net Inadvertant Interchange					333	0	333	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,369	0	1,369	0.0				
25. Interchange and Wheeling Losses					4,212	6,400	(2,188)	(34.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	58,483,057	58,432,644	50,413	0.1	2,756,435	2,628,547	127,888	4.9	2.12169	2.22300	(0.10131)	(4.6)
27. Net Unbilled	(1,634,974) (a)	(2,069,657) (a)	434,683	(21.0)	(77,060)	(93,102)	16,042	(17.2)	(0.05931)	(0.07874)	0.01943	(24.7)
28. Company Use	165,725 (a)	151,164 (a)	14,561	9.6	7,811	6,800	1,011	14.9	0.00608	0.00585	0.00023	3.9
29. T & D Losses	2,141,252 (a)	2,898,503 (a)	(757,251)	(26.1)	100,922	130,387	(29,465)	(22.6)	0.07858	0.11215	(0.03357)	(29.9)
30. System KWH Sales	58,483,057	58,432,644	50,413	0.1	2,724,762	2,584,462	140,300	5.4	2.14635	2.26092	(0.11457)	(5.1)
31. Wholesale KWH Sales	(426,212)	(202,059)	(224,153)	110.9	(19,591)	(8,980)	(10,611)	118.2	2.17555	2.25010	(0.07455)	(3.3)
32. Jurisdictional KWH Sales	58,056,845	58,230,585	(173,740)	(0.3)	2,705,171	2,575,482	129,689	5.0	2.14614	2.26096	(0.11482)	(5.1)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	58,064,392	58,238,155	(173,763)	(0.3)	2,705,171	2,575,482	129,689	5.0	2.14642	2.26125	(0.11483)	(5.1)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	819,551	822,495	(2,944)	(0.4)	2,705,171	2,575,482	129,689	5.0	0.03030	0.03194	(0.00164)	(5.1)
36. Adjustment - Oil Below the Discharge Valve	(4,922)	0	(4,922)	0.0	2,705,171	2,575,482	129,689	5.0	(0.00018)	0.00000	(0.00018)	0.0
37. True-up *	(2,669,580)	(2,669,580)	0	0.0	2,705,171	2,575,482	129,689	5.0	(0.09868)	(0.10365)	0.00497	(4.8)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	56,209,441	56,391,070	(181,629)	(0.3)	2,705,171	2,575,482	129,689	5.0	2.07785	2.18953	(0.11168)	(5.1)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.07957	2.19135	(0.11178)	(5.1)
41. GPIF * (Already Adjusted for Taxes)	(121,182)	(121,182)	0	0.0	2,705,171	2,575,482	129,689	5.0	(0.00448)	(0.00471)	0.00023	(4.9)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	56,088,259	56,269,888	(181,629)	(0.3)	2,705,171	2,575,482	129,689	5.0	2.07509	2.18664	(0.11155)	(5.1)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.075	2.187	(0.112)	(5.1)

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	23,111,738	30,413,718	(7,301,980)	(24.0)	53,896,015	62,929,684	(9,033,669)	(14.4)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	886,914	4,031,360	(3,144,446)	(78.0)	2,296,856	7,742,540	(5,445,684)	(70.3)
3. FUEL COST OF PURCHASED POWER	3,256,486	932,000	2,324,486	249.4	5,360,457	1,650,700	3,709,757	224.7
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	750,352	853,700	(103,348)	(12.1)	1,447,980	1,546,900	(98,920)	(6.4)
4. ENERGY COST OF ECONOMY PURCHASES	5,258	7,000	(1,742)	(24.9)	80,137	53,900	26,237	48.7
5. TOTAL FUEL & NET POWER TRANSACTION	26,236,920	28,175,058	(1,938,138)	(6.9)	58,487,733	58,438,644	49,089	0.1
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(2,528)	(3,000)	472	(15.7)	(4,676)	(6,000)	1,324	(22.1)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	26,234,392	28,172,058	(1,937,666)	(6.9)	58,483,057	58,432,644	50,413	0.1
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,263,522	1,213,318	50,204	4.1	2,705,171	2,575,482	129,689	5.0
2. NONJURISDICTIONAL SALES	5,232	3,286	1,946	59.2	19,591	8,980	10,611	118.2
3. TOTAL SALES	1,268,754	1,216,604	52,150	4.3	2,724,762	2,584,462	140,300	5.4
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9958763	0.9972990	(0.0014227)	(0.1)	0.9928100	0.9965254	(0.0037154)	(0.4)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998
REVISED WITH DEC. 1998 FILING

	CURRENT MONTH				PERIOD TO DATE			
C. TRUE-UP CALCULATION	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. JURISDICTIONAL FUEL REVENUE	29,067,537	27,031,564	2,035,973	7.5	62,463,815	57,397,360	5,066,455	8.8
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	1,334,790	1,334,790	0	0.0	2,669,580	2,669,580	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	121,182	121,182	0	0.0
c. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	30,462,918	28,426,945	2,035,973	7.2	65,254,577	60,188,122	5,066,455	8.4
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	26,234,392	28,172,058	(1,937,666)	(6.9)	58,483,057	58,432,644	50,413	0.1
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9958763	0.9972990	(0.0014227)	(0.1)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	26,126,212	28,095,965	(1,969,753)	(7.0)	58,056,845	58,230,585	(173,740)	(0.3)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	26,129,608	28,099,617	(1,970,009)	(7.0)	58,064,392	58,238,155	(173,763)	(0.3)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	411,399	411,399	0	0.0	825,329	825,329	0	0.0
6D.(LINE 6C x LINE 5)	409,703	410,288	(585)	(0.1)	819,551	822,495	(2,944)	(0.4)
6E.FUEL CREDIT DIFFERENTIAL -FMPA	0	0	0	0.0	0	0	0	0.0
6F. OTHER ADJ.(OIL BELOW DISCHG. VALVE)	0	0	0	0.0	(4,922)	0	(4,922)	0.0
6G. JURISDIC. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND ADJUSTMENTS	26,539,311	28,509,905	(1,970,594)	(6.9)	58,879,021	59,060,650	(181,629)	(0.3)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6G)	3,923,607	(82,960)	4,006,567	(4,829.5)	6,375,556	1,127,472	5,248,084	465.5
8. INTEREST PROVISION FOR THE MONTH	42,553	15,954	26,599	166.7	75,839	35,665	40,174	112.6
9. TRUE-UP & INT. PROV. BEG. OF MONTH	8,279,486	3,846,308	4,433,178	115.3	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	53,414	53,414	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(1,334,790)	(1,334,790)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	10,964,270	2,497,926	8,466,344	338.9	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998

SCHEDULE A2
PAGE 3 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	8,332,900	3,899,722	4,433,178	113.7	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	10,921,717	2,481,972	8,439,745	340.0	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	19,254,617	6,381,694	12,872,923	201.7	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	9,627,309	3,190,847	6,436,462	201.7	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.100	6.000	(0.900)	(15.0)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.500	6.000	(0.500)	(8.3)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	10.600	12.000	(1.400)	(11.7)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.300	6.000	(0.700)	(11.7)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.442	0.500	(0.058)	(11.6)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	42,553	15,954	26,599	166.7	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER, 1998

SCHEDULE A3
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	156,404	88,225	68,179	77.3	854,436	402,505	451,931	112.3
2	LIGHT OIL	530,153	326,794	203,359	62.2	1,979,750	581,047	1,398,703	240.7
3	COAL	22,425,181	29,998,699	(7,573,518)	(25.2)	51,061,829	61,946,132	(10,884,303)	(17.6)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	23,111,738	30,413,718	(7,301,980)	(24.0)	53,896,015	62,929,684	(9,033,669)	(14.4)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,653	2,497	2,156	86.3	26,406	11,234	15,172	135.1
9	LIGHT OIL	19,603	10,496	9,107	86.8	60,300	17,076	43,224	253.1
10	COAL	1,119,901	1,399,991	(280,090)	(20.0)	2,504,776	2,903,049	(398,273)	(13.7)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,144,157	1,412,984	(268,827)	(19.0)	2,591,482	2,931,359	(339,877)	(11.6)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	8,619	5,650	2,969	52.5	54,295	25,812	28,483	110.3
16	LIGHT OIL (BBL)	24,555	14,768	9,787	66.3	97,736	26,460	71,276	269.4
17	COAL (TON)	511,086	633,640	(122,554)	(19.3)	1,145,718	1,320,871	(175,153)	(13.3)
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	54,146	35,707	18,439	51.6	342,430	163,153	179,277	109.9
22	LIGHT OIL	142,314	85,808	56,506	65.9	567,562	153,754	413,808	269.1
23	COAL	11,606,045	14,377,157	(2,771,112)	(19.3)	26,003,273	29,889,309	(3,886,036)	(13.0)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	11,802,505	14,498,672	(2,696,167)	(18.6)	26,913,265	30,206,216	(3,292,951)	(10.9)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.41	0.18	0.23	-	1.02	0.38	0.64	-
29	LIGHT OIL	1.71	0.74	0.97	-	2.33	0.58	1.75	-
30	COAL	97.88	99.08	(1.20)	-	96.65	99.04	(2.39)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	18.15	15.62	2.53	16.2	15.74	15.59	0.15	1.0
36	LIGHT OIL ($/BBL)	21.59	22.13	(0.54)	(2.4)	20.26	21.96	(1.70)	(7.7)
37	COAL ($/TON)	43.88	47.34	(3.46)	(7.3)	44.57	46.90	(2.33)	(5.0)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.89	2.47	0.42	17.0	2.50	2.47	0.03	1.2
42	LIGHT OIL	3.73	3.81	(0.08)	(2.1)	3.49	3.78	(0.29)	(7.7)
43	COAL	1.93	2.09	(0.16)	(7.7)	1.96	2.07	(0.11)	(5.3)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.96	2.10	(0.14)	(6.7)	2.00	2.08	(0.08)	(3.8)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: NOVEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	11,637	14,300	(2,663)	(18.6)	12,968	14,523	(1,555)	(10.7)
49	LIGHT OIL	7,260	8,175	(915)	(11.2)	9,412	9,004	408	4.5
50	COAL	10,363	10,269	94	0.9	10,381	10,296	85	0.8
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,315	10,261	54	0.5	10,385	10,305	80	0.8
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.36	3.53	(0.17)	(4.8)	3.24	3.58	(0.34)	(9.5)
56	LIGHT OIL	2.70	3.11	(0.41)	(13.2)	3.28	3.40	(0.12)	(3.5)
57	COAL	2.00	2.14	(0.14)	(6.5)	2.04	2.13	(0.09)	(4.2)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.02	2.15	(0.13)	(6.0)	2.08	2.15	(0.07)	(3.3)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: NOVEMBER, 1998

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	34	0	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	34	-170	0.0	100.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	34	0	0.0	97.4	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	43	0	0.0	4.3	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	55	0	0.0	74.3	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	200	-170	0.0	71.9	0.0	0	HVY.OIL	1482	6323347	9371.2	22869	0.00	15.43
GAN.#1	114	43192	52.6	71.9	77.4	10992	COAL	20526	23129178	474749.5	956256	2.21	46.59
GAN.#2	108	39292	50.5	82.9	70.7	11337	COAL	19436	22918481	445443.6	905476	2.30	46.59
GAN.#3	155	77068	69.1	87.0	72.2	11819	COAL	47625	19125781	910865.3	2218733	2.88	46.59
GAN.#4	179	23340	18.1	23.4	57.6	11285	COAL	11344	23218644	263392.3	528489	2.26	46.59
GAN.#5	232	66401	39.8	47.7	77.3	10140	COAL	27040	24900899	673320.3	1259728	1.90	46.59
GAN.#6	392	131444	46.6	58.4	72.2	10346	COAL	57325	23723320	1359939.3	2670632	2.03	46.59
GANNON STA.	1180	380737	44.8	58.3	71.4	10841	COAL	183296	22519369	4127710.3	8539314	2.24	46.59
B.B.#1	431	192607	62.1	71.3	70.6	10197	COAL	84527	23235360	1964015.3	3452295	1.79	40.84
B.B.#2	426	179815	58.6	66.7	67.1	10362	COAL	80491	23149100	1863294.2	3287454	1.83	40.84
B.B.#3	438	251651	79.8	87.4	79.8	9822	COAL	109718	22527260	2471645.9	4481159	1.78	40.84
B.B. 1 - 3	1295	624073	66.9	75.2	72.6	10093	COAL	274736	22927303	6298955.4	11220908	1.80	40.84
B.B.#4	447	47468	14.7	18.8	74.6	10452	COAL	22907	21658358	496128.0	1184752	2.50	51.72
B.B. STA.	1742	671541	53.5	60.8	73.1	10119	COAL	297643	22829643	6795083.4	12405660	1.85	41.68
SEB-PHIL. #1(HVY OIL)	17	2393	19.6	97.3	79.7	9282	HVY.OIL	3541	6272861	22212.2	66253	2.77	18.71
SEB-PHIL. #2(HVY OIL)	17	2430	19.9	100.0	75.9	9285	HVY.OIL	3596	6274221	22562.1	67282	2.77	18.71
SEB-PHILLIPS TOTAL	34	4823	19.7	98.7	77.8	9283	HVY.OIL	7137	6273546	44774.3	133535	2.77	18.71
POLK COAL	250	67623	37.6	41.3	91.0	10104	COAL	30147	22664000	683251.6	1480207	2.19	49.10
POLK OIL	245	19310	10.9	16.2	67.4	7113	LGT.OIL	23708	5793606	137354.8	513417	2.66	21.66
POLK TOTAL	250	86933	48.5	57.5	-	9440	-	-	-	820606.4	1993624	2.29	-
GAN.C.T.#1	17	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	20	0.2	100.0	39.2	20925	LGT.OIL	72	5812500	418.5	1423	7.12	19.76
B.B.C.T.#2	80	137	0.2	100.0	57.1	15651	LGT.OIL	366	5858470	2144.2	7232	5.28	19.76
B.B.C.T.#3	80	136	0.2	97.4	42.5	17622	LGT.OIL	409	5859658	2396.6	8081	5.94	19.76
C.T. TOTAL	194	293	0.2	98.9	15.1	16926	LGT.OIL	847	5855136	4959.3	16736	5.71	19.76
TOT. COAL (GN,BB,POLK)	3172	1119901	49.0	58.3	73.9	10363	COAL	511086	22708596	11606045.3	22425181	2.00	43.88
SYSTEM	3600	1144157	44.1	61.6	68.2	10315	-	-	-	11802504.9	23111738	2.02	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)								
1	PURCHASES:								
2	UNITS (BBL)	84,237	5,650	78,587	1,390.9	97,323	25,812	71,511	277.0
3	UNIT COST ($/BBL)	15.01	15.27	(0.26)	(1.7)	15.54	14.88	0.66	4.4
4	AMOUNT ($)	1,264,308	86,289	1,178,019	1,365.2	1,511,935	383,991	1,127,944	293.7
5	BURNED:								
6	UNITS (BBL)	8,619	5,650	2,969	52.5	54,295	25,812	28,483	110.3
7	UNIT COST ($/BBL)	18.15	15.62	2.53	16.2	15.74	15.59	0.15	1.0
8	AMOUNT ($)	156,404	88,225	68,179	77.3	854,436	402,505	451,931	112.3
9	ENDING INVENTORY:								
10	UNITS (BBL)	172,881	127,276	45,605	35.8	172,881	127,276	45,605	35.8
11	UNIT COST ($/BBL)	14.72	14.26	0.46	3.2	14.72	14.26	0.46	3.2
12	AMOUNT ($)	2,544,146	1,815,156	728,990	40.2	2,544,146	1,815,156	728,990	40.2
13									
14	DAYS SUPPLY:	296	533	(237)	(44.5)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	39,910	26,721	13,189	49.4	121,897	51,988	69,909	134.5
17	UNIT COST ($/BBL)	22.88	22.77	0.11	0.5	21.40	22.58	(1.18)	(5.2)
18	AMOUNT ($)	913,244	608,404	304,840	50.1	2,608,510	1,173,852	1,434,658	122.2
19	BURNED:								
20	UNITS (BBL)	24,555	14,768	9,787	66.3	97,736	26,460	71,276	269.4
21	UNIT COST ($/BBL)	21.59	22.13	(0.54)	(2.4)	20.26	21.96	(1.70)	(7.7)
22	AMOUNT ($)	530,153	326,794	203,359	62.2	1,979,750	581,047	1,398,703	240.7
23	ENDING INVENTORY:								
24	UNITS (BBL)	38,148	76,883	(38,735)	(50.4)	38,148	76,883	(38,735)	(50.4)
25	UNIT COST ($/BBL)	21.28	21.99	(0.71)	(3.2)	21.28	21.99	(0.71)	(3.2)
26	AMOUNT ($)	811,852	1,690,618	(878,766)	(52.0)	811,852	1,690,618	(878,766)	(52.0)
27									
28	DAYS SUPPLY: NORMAL	32	69	(37)	(53.6)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	5	11	(6)	(54.5)	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	634,644	680,871	(46,227)	(6.8)	1,608,867	1,418,742	190,125	13.4
32	UNIT COST ($/TON)	42.29	47.67	(5.38)	(11.3)	43.58	47.24	(3.66)	(7.7)
33	AMOUNT ($)	26,837,444	32,456,227	(5,618,783)	(17.3)	70,112,822	67,015,701	3,097,121	4.6
34	BURNED:								
35	UNITS (TONS)	511,086	633,640	(122,554)	(19.3)	1,145,718	1,320,871	(175,153)	(13.3)
36	UNIT COST ($/TON)	43.88	47.34	(3.46)	(7.3)	44.57	46.90	(2.33)	(5.0)
37	AMOUNT ($)	22,425,181	29,998,699	(7,573,518)	(25.2)	51,061,829	61,946,132	(10,884,303)	(17.6)
38	ENDING INVENTORY:								
39	UNITS (TONS)	901,670	942,173	(40,503)	(4.3)	901,670	942,173	(40,503)	(4.3)
40	UNIT COST ($/TON)	43.72	46.63	(2.91)	(6.2)	43.72	46.63	(2.91)	(6.2)
41	AMOUNT ($)	39,423,007	43,935,518	(4,512,511)	(10.3)	39,423,007	43,935,518	(4,512,511)	(10.3)
42									
43	DAYS SUPPLY:	40	46	(6)	(13.0)	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER, 1998

	OTHER		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	8,370
FUEL ANALYSIS	0
TOTAL	8,370

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(12,715)	(252,068)
OTHER USAGE	(1,005)	(20,871)
TOTAL	(13,720)	(272,939)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	243,698
FUEL ANALYSIS	12,410
AERIAL SURVEY ADJ.	84,537
ADDITIVES	181,130
PROPANE IGNITION	461
TOTAL	522,236

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF NOVEMBER, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	174,980.0	0.0	174,980.0	1.602	2.150	2,803,900.00	3,762,100.00	766,560.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,625.0	0.0	5,625.0	1.564	1.564	88,000.00	88,000.00	
VARIOUS	SEPARATED	SCH. -D	29,932.0	0.0	29,932.0	1.540	1.810	461,000.00	541,700.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS		CONTRACT	5,143.0	0.0	5,143.0	2.364	3.309	121,600.00	170,200.00	
HARDEE POWER PARTNERS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKELAND/FMPA		SCH. -J	766.0	0.0	766.0	1.632	1.632	12,500.00	12,500.00	
VARIOUS	JURISDICTIONAL									
TOTAL INCLUDING VARIABLE O & M COSTS		-	216,446.0	0.0	216,446.0	1.611	2.113	3,487,000.00	4,574,500.00	766,560.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(222,200.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						766,560.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	216,446.0	0.0	216,446.0	1.863	2.113	4,031,360.00	4,574,500.00	766,560.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	2,694.0	0.0	2,694.0	1.793	2.047	48,299.68	55,132.94	5,466.61
FLA. PWR. & LIGHT		ECON.-C	1,013.0	0.0	1,013.0	1.803	2.000	18,268.89	20,259.71	1,592.66
CITY OF LAKELAND		ECON.-C	1.0	0.0	1.0	1.869	2.135	18.69	21.35	2.13
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		ECON.-C	31.0	0.0	31.0	1.798	2.376	557.50	736.56	143.25
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	30.0	0.0	30.0	1.840	2.400	551.91	720.02	134.49
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	4,562.0	0.0	4,562.0	1.775	2.011	80,988.70	91,730.44	8,593.39
SEMINOLE ELECTRIC CO-OP		ECON.-C	193.0	0.0	193.0	1.821	2.385	3,513.64	4,603.17	871.62
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	5,328.0	0.0	5,328.0	1.725	2.008	91,928.36	106,972.05	12,034.95
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	133.0	0.0	133.0	1.836	2.618	2,441.74	3,482.22	832.38
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	9,360.0	0.0	9,360.0	1.689	1.835	158,084.30	171,783.46	
REEDY CREEK	SEPAR.	SCH. -D	14,400.0	0.0	14,400.0	1.340	1.608	192,960.00	231,552.00	
WAUCHULA	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.340	1.608	48,240.00	57,888.00	
FT. MEADE	SEPAR.	SCH. -D	3,046.0	0.0	3,046.0	1.340	1.608	10,816.40	48,979.68	
ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	780.0	0.0	780.0	2.444	3.108	19,063.20	24,242.40	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	3,318.0	23.7	3,294.3	1.872	1.872	61,672.81	61,672.81	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	795.0	0.0	795.0	1.555	1.555	12,366.12	12,366.12	
FLA. PWR. CORP.	JURISD.	SCH. -J	109.0	0.0	109.0	1.934	1.934	2,107.73	2,107.73	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -J	64,700.0	64,700.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF NOVEMBER, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
HARDEE PWR. PARTNERS TO FPC	ECON.-C	70.0	0.0	70.0	2.516	2.715	1,761.16	1,900.73	111.66 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	44.0	0.0	44.0	2.542	2.871	1,118.28	1,263.20	115.94 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	10.0	0.0	10.0	1.730	1.914	173.00	191.38	14.70 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKE WORTH	ECON.-C	15.0	0.0	15.0	1.967	2.287	295.05	343.06	38.41 *
HARDEE POWER PART. TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PARTNERS TO FPC	SCH. -J	2,236.0	0.0	2,236.0	2.447	2.447	54,723.86	54,723.86	
ADJUSTMENTS TO PRIOR MONTHS									
HARDEE POWER PARTNERS 10/98 SEPAR.	CONTRACT	(23,333.0)	0.0	(23,333.0)	2.083	2.717	(486,026.39)	(633,957.61)	
HARDEE POWER PARTNERS 10/98 SEPAR.	CONTRACT	23,333.0	0.0	23,333.0	2.444	3.108	570,258.52	725,189.64	
SEM ELEC CO-OP PRECO-1 6/98 JURISD.	SCH. -D	(3,783.0)	(234.0)	(3,549.0)	1.636	1.636	(58,072.37)	(58,072.37)	
SEM ELEC CO-OP PRECO-1 6/98 JURISD.	SCH. -D	3,783.0	234.0	3,549.0	1.556	1.556	55,213.82	55,213.82	
SEM ELEC CO-OP PRECO-1 7/98 JURISD.	SCH. -D	(4,541.0)	(432.1)	(4,108.9)	2.322	2.322	(95,399.11)	(95,399.11)	
SEM ELEC CO-OP PRECO-1 7/98 JURISD.	SCH. -D	4,541.0	432.1	4,108.9	2.188	2.188	89,900.08	89,900.08	
SEM ELEC CO-OP PRECO-1 8/98 JURISD.	SCH. -D	(4,722.0)	(573.9)	(4,148.1)	2.624	2.624	(108,865.93)	(108,865.93)	
SEM ELEC CO-OP PRECO-1 8/98 JURISD.	SCH. -D	4,722.0	573.9	4,148.1	2.437	2.437	101,092.25	101,092.25	
SEM ELEC CO-OP PRECO-1 9/98 JURISD.	SCH. -D	(4,188.0)	(317.2)	(3,870.8)	2.302	2.302	(89,109.42)	(89,109.42)	
SEM ELEC CO-OP PRECO-1 9/98 JURISD.	SCH. -D	4,188.0	317.2	3,870.8	2.176	2.176	84,234.01	84,234.01	
SEM ELEC CO-OP HARDEE 6/98 JURISD.	SCH. -D	(796.0)	0.0	(796.0)	1.614	1.614	(12,849.41)	(12,849.41)	
SEM ELEC CO-OP HARDEE 6/98 JURISD.	SCH. -D	796.0	0.0	796.0	1.509	1.509	12,011.36	12,011.36	
SEM ELEC CO-OP HARDEE 7/98 JURISD.	SCH. -D	(604.0)	0.0	(604.0)	1.665	1.665	(10,057.31)	(10,057.31)	
SEM ELEC CO-OP HARDEE 7/98 JURISD.	SCH. -D	604.0	0.0	604.0	1.453	1.453	8,773.70	8,773.70	
SEM ELEC CO-OP HARDEE 8/98 JURISD.	SCH. -D	(961.0)	0.0	(961.0)	1.756	1.756	(16,873.73)	(16,873.73)	
SEM ELEC CO-OP HARDEE 8/98 JURISD.	SCH. -D	961.0	0.0	961.0	1.495	1.495	14,371.32	14,371.32	
SEM ELEC CO-OP HARDEE 9/98 JURISD.	SCH. -D	(641.0)	0.0	(641.0)	1.799	1.799	(11,531.70)	(11,531.70)	
SEM ELEC CO-OP HARDEE 9/98 JURISD.	SCH. -D	641.0	0.0	641.0	1.597	1.597	10,237.44	10,237.44	
SUB-TOTAL ECONOMY POWER SALES		14,124.0	0.0	14,124.0	1.769	2.035	249,916.60	287,356.83	29,952.19
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		30,406.0	0.0	30,406.0	1.447	1.678	440,100.70	510,203.14	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		4,113.0	23.7	4,089.3	1.152	1.152	47,113.93	47,113.93	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		2,345.0	0.0	2,345.0	2.424	2.424	56,831.59	56,831.59	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		780.0	0.0	780.0	13.243	14.804	103,295.33	115,474.43	
SUB-TOTAL OTHER SCHEDULE D POWER SALES		61,200.0	61,200.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	112,968.0	61,223.7	51,744.3	1.734	1.965	897,258.15	1,016,979.92	29,952.19
LESS VARIABLE O & M COSTS	-						(23,354.95)		
LESS VARIABLE O & M COSTS - HARDEE	-						(19.46)		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(16,922.26)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						29,952.19		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	112,968.0	61,223.7	51,744.3	1.714	1.965	886,913.67	1,016,979.92	29,952.19
CURRENT MONTH:									
DIFFERENCE	-	(103,478.0)	61,223.7	(164,701.7)	(0.149)	(0.148)	(3,144,446.33)	(3,557,520.08)	(736,607.81)
DIFFERENCE %	-	(47.8)	0.0	(76.1)	(8.0)	(7.0)	(78.0)	(77.8)	(96.1)
PERIOD TO DATE:									
ACTUAL	-	265,165.0	124,795.2	140,369.8	1.636	1.924	2,296,855.61	2,700,876.56	83,484.64
ESTIMATED	-	422,225.0	0.0	422,225.0	1.834	2.087	7,742,540.00	8,811,800.00	1,164,640.00
DIFFERENCE	-	(157,060.0)	124,795.2	(281,855.2)	(0.198)	(0.163)	(5,445,684.39)	(6,110,923.44)	(1,381,155.36)
DIFFERENCE %	-	(37.2)	0.0	(66.8)	(10.8)	(7.8)	(70.3)	(69.3)	(94.3)

* THE PROFITS REFLECTED ARE ONLY ON ITS 10%. SEC 60% OR $5,862.34 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF NOVEMBER, 1998

SCHEDULE A7

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:									
VARIOUS		EMER.	399.0	0.0	261.0	138.0	5.145	5.145	7,100.00
HARDEE POWER PARTNERS		IPP	28,364.0	0.0	0.0	28,364.0	3.261	3.261	924,900.00
VARIOUS		OTHER	56,795.0	56,795.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	85,558.0	56,795.0	261.0	28,502.0	3.270	3.270	932,000.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	99,324.0	0.0	0.0	99,324.0	2.274	2.274	2,258,682.29
HARDEE PWR. PART.-OTHERS		IPP	2,375.0	0.0	0.0	2,375.0	2.284	2.284	54,236.88
FLA. POWER CORP.		SCH.-Ja	247.0	0.0	247.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-Jc	16,042.0	0.0	0.0	16,042.0	3.050	3.050	489,283.15
FLA. POWER & LIGHT		SCH.-Ja	683.0	0.0	683.0	0.0	0.000	0.000	0.00
FLA. POWER & LIGHT		SCH.-Jc	9,397.0	0.0	0.0	9,397.0	3.277	3.277	307,949.70
ORLANDO UTIL. COMM.		SCH.-Jc	3,076.0	0.0	0.0	3,076.0	3.190	3.190	98,114.75
THE ENERGY AUTHORITY		SCH.-Jc	2,771.0	0.0	0.0	2,771.0	2.863	ERR	79,346.66
PECO		OTHER	37,950.0	37,950.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS:									
HARDEE PWR.PART.-NATIVE	10/98	IPP	(61,014.0)	0.0	0.0	(61,014.0)	2.056	2.056	(1,254,385.00)
HARDEE PWR.PART.-NATIVE	10/98	IPP	61,014.0	0.0	0.0	61,014.0	2.015	2.015	1,229,561.45
PECO	9/98	SCH.-Ja	(879.0)	0.0	(488.0)	(391.0)	4.836	4.836	(18,908.53)
PECO	9/98	SCH.-Ja	879.0	0.0	488.0	391.0	4.653	4.653	18,193.29
PECO	9/98	SCH.-Jc	(724.0)	0.0	0.0	(724.0)	4.738	4.738	(34,302.07)
PECO	9/98	SCH.-Jc	724.0	0.0	0.0	724.0	4.555	4.555	32,980.00
THE ENERGY AUTHORITY	9/98	SCH.-Ja	(2,194.0)	0.0	(1,487.6)	(706.4)	4.792	4.792	(33,848.84)
THE ENERGY AUTHORITY	9/98	SCH.-Ja	2,194.0	0.0	1,487.6	706.4	4.670	4.670	32,990.23
THE ENERGY AUTHORITY	9/98	SCH.-Jc	(2,797.0)	0.0	0.0	(2,797.0)	4.170	4.170	(116,632.51)
THE ENERGY AUTHORITY	9/98	SCH.-Jc	2,797.0	0.0	0.0	2,797.0	4.048	4.048	113,225.00
TOTAL			195,115.0	61,200.0	930.0	132,985.0	2.449	2.449	3,256,486.45
CURRENT MONTH:									
DIFFERENCE		-	109,557.0	4,405.0	669.0	104,483.0	(0.821)	(0.821)	2,324,486.45
DIFFERENCE %		-	128.0	7.8	256.3	366.6	(25.1)	(25.1)	249.4
PERIOD TO DATE:									
ACTUAL		-	364,742.0	124,525.0	9,924.9	230,292.1	2.328	2.328	5,360,457.09
ESTIMATED		-	164,189.0	0.0	1,602.0	162,587.0	1.015	1.015	1,650,700.00
DIFFERENCE		-	200,553.0	124,525.0	8,322.9	67,705.1	1.313	1.313	3,709,757.09
DIFFERENCE %		-	122.1	0.0	519.5	41.6	129.4	129.4	224.7

SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF NOVEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) -----CENTS/KWH----- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	38,045.0	0.0	0.0	38,045.0	2.244	2.244	853,700.00
TOTAL	-	38,045.0	0.0	0.0	38,045.0	2.244	2.244	853,700.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	252.0	0.0	0.0	252.0	2.296	2.296	5,786.17
McKAY BAY REFUSE	COGEN.	10,898.0	0.0	0.0	10,898.0	1.938	1.938	211,193.39
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	1,288.0	0.0	0.0	1,288.0	2.359	2.359	30,386.74
HILLSBOROUGH COUNTY	COGEN.	19,545.0	0.0	0.0	19,545.0	1.938	1.938	378,703.84
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	474.0	0.0	0.0	474.0	2.681	2.681	12,707.67
FARMLAND HYDRO LP	COGEN.	27.0	0.0	0.0	27.0	1.856	1.856	501.20
IMC-AGRICO-S. PIERCE	COGEN.	218.0	0.0	0.0	218.0	2.904	2.904	6,331.69
AUBURNDALE POWER PARTNERS	COGEN.	1,168.0	0.0	0.0	1,168.0	1.685	1.685	19,680.32
ORANGE COGENERATION L.P.	COGEN.	5,121.0	0.0	0.0	5,121.0	1.846	1.846	94,538.27
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	35.0	(35.0)	4.255	4.255	(1,489.12)
SUB-TOTAL FOR NOV., 1998	-	38,991.0	0.0	35.0	38,956.0	1.947	1.947	758,340.17
ADJUSTMENTS FOR SEPT., 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(9,697.0)	0.0	0.0	(9,697.0)	1.904	1.904	(184,655.03)
		9,697.0	0.0	0.0	9,697.0	1.883	1.883	182,558.73
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(15,101.0)	0.0	0.0	(15,101.0)	1.896	1.896	(286,376.25)
		15,101.0	0.0	0.0	15,101.0	1.876	1.876	283,240.18
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.							
FARMLAND INDUSTRIES	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(7,153.0)	0.0	0.0	(7,153.0)	1.920	1.920	(137,355.92)
		7,153.0	0.0	0.0	7,153.0	1.882	1.882	134,600.55
AS AVAILABLE ASSIGNMENT	COGEN.							
SUB-TOTAL FOR SEPT., 1998 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(7,987.74)
GRAND TOTAL		38,991.0	0.0	35.0	38,956.0	1.926	1.926	750,352.43
CURRENT MONTH:								
DIFFERENCE	-	946.0	0.0	35.0	911.0	(0.318)	(0.318)	(103,347.57)
DIFFERENCE %	-	2.5	0.0	0.0	2.4	(14.2)	(14.2)	(12.1)
PERIOD TO DATE:								
ACTUAL		75,332.0	0.0	137.0	75,195.0	1.926	1.926	1,447,980.26
ESTIMATED		76,957.0	0.0	0.0	76,957.0	2.010	2.010	1,546,900.00
DIFFERENCE	-	(1,625.0)	0.0	137.0	(1,762.0)	(0.084)	(0.084)	(98,919.74)
DIFFERENCE %	-	(2.1)	0.0	0.0	(2.3)	(4.2)	(4.2)	(6.4)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF NOVEMBER, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $.	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	262.0	2.672	7,000.00	3.855	10,100.00	3,100.00
TOTAL	-	262.0	2.672	7,000.00	3.855	10,100.00	3,100.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	64.0	1.987	1,271.36	2.428	1,553.92	282.56
FLA. PWR. & LIGHT	ECON.-C	98.0	4.236	4,150.89	4.236	4,151.59	0.70
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	4.0	3.082	123.26	3.412	136.48	13.22
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C *	0.0	0.000	1,518.00	0.000	0.00	(1,518.00)
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ADJUSTMENT TO OCT. 1998							
FLA. PWR. & LIGHT	ECON.-C	(669.0)	3.575	(23,917.52)	3.581	(23,959.08)	(41.56)
FLA. PWR. & LIGHT	ECON.-C	669.0	3.574	23,910.34	3.581	23,959.08	48.74
THE ENERGY AUTHORITY	ECON.-C	(608.0)	3.809	(23,161.25)	4.633	(28,170.76)	(5,009.51)
THE ENERGY AUTHORITY	ECON.-C	608.0	3.510	21,338.79	4.633	28,170.76	6,831.97
TALLAHASSEE	ECON.-C	(104.0)	3.299	(3,431.39)	4.000	(4,159.98)	(728.59)
TALLAHASSEE	ECON.-C	104.0	3.313	3,445.91	4.000	4,159.98	714.07
SEMINOLE ELECTRIC CO-OP.	ECON.-C	(164.0)	2.697	(4,422.43)	3.139	(5,148.54)	(726.11)
SEMINOLE ELECTRIC CO-OP.	ECON.-C	164.0	2.703	4,432.45	3.139	5,148.54	716.09
TOTAL	-	166.0	3.168	5,258.41	3.519	5,841.99	583.58
CURRENT MONTH:							
DIFFERENCE	-	(96.0)	0.496	(1,741.59)	(0.336)	(4,258.01)	(2,516.42)
DIFFERENCE %	-	(36.6)	18.6	(24.9)	(8.7)	(42.2)	(81.2)
PERIOD TO DATE:							
ACTUAL		2,346.0	3.416	80,137.25	3.879	91,002.03	10,864.78
ESTIMATED		1,752.0	3.076	53,900.00	4.024	70,500.00	16,600.00
DIFFERENCE	-	594.0	0.340	26,237.25	(0.145)	20,502.03	(5,735.22)
DIFFERENCE %	-	33.9	11.1	48.7	(3.6)	29.1	(34.5)

* TRANSMISSION CHARGES

COMMISSION SCHEDULES A1 - A9

OCTOBER 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	30,784,277	32,515,966	(1,731,689)	(5.3)	1,447,325	1,518,375	(71,050)	(4.7)	2.12698	2.14150	(0.01452)	(0.7)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,148)	(3,000)	852	(28.4)	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	(0.00015)	(0.00020)	0.00005	(25.0)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	30,782,129	32,512,966	(1,730,837)	(5.3)	1,447,325	1,518,375	(71,050)	(4.7)	2.12683	2.14130	(0.01447)	(0.7)
6. Fuel Cost of Purchased Power - Firm (A7)	2,103,971	718,700	1,385,271	192.7	97,307	18,602	78,705	423.1	2.16220	3.86356	(1.70136)	(44.0)
7. Energy Cost of Sch C,I Economy Purchases (Broker) (A9)	74,879	46,900	27,979	59.7	2,180	1,490	690	46.3	3.43482	3.14765	0.28717	9.1
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	697,628	693,200	4,428	0.6	36,239	38,912	(2,673)	(6.9)	1.92508	1.78146	0.14362	8.1
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	2,876,478	1,458,800	1,417,678	97.2	135,726	59,004	76,722	130.0	2.11933	2.47237	(0.35304)	(14.3)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,583,051	1,577,379	5,672	0.4				
14. Fuel Cost of Economy Sales (A6)	447,170	2,283,600	(1,836,430)	(80.4)	28,189	162,015	(133,826)	(82.6)	1.58633	1.40950	0.17683	12.5
15. Gain on Economy Sales - 80% (A6)	53,532	698,080	(644,548)	(92.3)	28,189 (a)	162,015 (a)	(133,826)	(82.6)	0.18990	0.43087	(0.24097)	(55.9)
16. Fuel Cost of Sch. D Separ. Sales (A6)	330,378	483,000	(152,622)	(31.6)	31,947	31,282	665	2.1	1.03414	1.54402	(0.50988)	(33.0)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	102,926	90,500	12,426	13.7	5,157	5,711	(554)	(9.7)	1.99585	1.58466	0.41119	25.9
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	5,180	(5,180)	(100.0)	0	316	(316)	(100.0)	0.00000	1.61392	(1.61392)	(100.0)
20. Fuel Cost of NPP Sch. B Separ. Sales (A6)	475,936	150,900	325,036	215.4	23,333	6,455	16,878	261.5	2.03975	2.33772	(0.29797)	(12.7)
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	1,409,942	3,711,180	(2,301,238)	(62.0)	88,626	205,779	(117,153)	(56.9)	1.59089	1.80348	(0.21259)	(11.8)
23. Net Inadvertant Interchange					518	0	518	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,237	0	1,237	0.0				
25. Interchange and Wheeling Losses					2,072	3,100	(1,028)	(33.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	32,248,665	30,260,586	1,988,079	6.6	1,494,108	1,368,500	125,608	9.2	2.15839	2.21122	(0.05283)	(2.4)
27. Net Unbilled	(610,285)(a)	(1,562,050)(a)	951,765	(60.9)	(28,275)	(70,642)	42,367	(60.0)	(0.04085)	(0.13414)	0.07329	(54.2)
28. Company Use	85,731 (a)	75,181 (a)	10,550	14.0	3,972	3,400	572	16.8	0.00589	0.00550	0.00039	7.1
29. T & D Losses	1,346,900 (a)	1,501,065 (a)	(154,165)	(10.3)	62,403	67,884	(5,481)	(8.1)	0.09251	0.10974	(0.01723)	(15.7)
30. System KWH Sales	32,248,665	30,260,586	1,988,079	6.6	1,456,008	1,367,858	88,150	6.4	2.21487	2.21226	0.00261	0.1
31. Wholesale KWH Sales	(318,032)	(125,966)	(192,066)	152.5	(14,359)	(5,694)	(8,665)	152.2	2.21486	2.21226	0.00260	0.1
32. Jurisdictional KWH Sales	31,930,633	30,134,620	1,796,013	6.0	1,441,649	1,362,164	79,485	5.8	2.21487	2.21226	0.00261	0.1
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	31,934,784	30,138,538	1,796,246	6.0	1,441,649	1,362,164	79,485	5.8	2.21516	2.21255	0.00261	0.1
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	409,848	412,207	(2,359)	(0.6)	1,441,649	1,362,164	79,485	5.8	0.02843	0.03026	(0.00183)	(6.0)
36. Adjustment - Oil Below the Discharge Valve	(4,922)	0	(4,922)	0.0	1,441,649	1,362,164	79,485	5.8	(0.00034)	0.00000	(0.00034)	0.0
37. True-up *	(1,334,790)	(1,334,790)	0	0.0	1,441,649	1,362,164	79,485	5.8	(0.09259)	(0.09799)	0.00540	(5.5)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	31,004,920	29,215,955	1,788,965	6.1	1,441,649	1,362,164	79,485	5.8	2.15066	2.14482	0.00584	0.3
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.15245	2.14660	0.00585	0.3
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,441,649	1,362,164	79,485	5.8	(0.00420)	(0.00445)	0.00025	(5.6)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	30,944,329	29,155,364	1,788,965	6.1	1,441,649	1,362,164	79,485	5.8	2.14825	2.14215	0.00610	0.3
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.148	2.142	0.006	0.3

0

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: OCTOBER, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	30,784,277	32,515,966	(1,731,689)	(5.3)	1,447,325	1,518,375	(71,050)	(4.7)	2.12698	2.14150	(0.01452)	(0.7)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,148)	(3,000)	852	(28.4)	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	(0.00015)	(0.00020)	0.00005	(25.0)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,447,325 (a)	1,518,375 (a)	(71,050)	(4.7)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	30,782,129	32,512,966	(1,730,837)	(5.3)	1,447,325	1,518,375	(71,050)	(4.7)	2.12683	2.14130	(0.01447)	(0.7)
6. Fuel Cost of Purchased Power - Firm (A7)	2,103,971	718,700	1,385,271	192.7	97,307	18,602	78,705	423.1	2.16220	3.86356	(1.70136)	(44.0)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	74,879	46,900	27,979	59.7	2,180	1,490	690	46.3	3.43482	3.14765	0.28717	9.1
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. *Capacity Cost of Sch. E Economy Purchases*	*0*	*0*	*0*	*0.0*	0 (a)	0 (a)	*0*	*0.0*	*0.00000*	*0.00000*	*0.00000*	*0.0*
11. Payments to Qualifying Facilities (A8)	697,628	693,200	4,428	0.6	36,239	38,912	(2,673)	(6.9)	1.92508	1.78146	0.14362	8.1
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	2,876,478	1,458,800	1,417,678	97.2	135,726	59,004	76,722	130.0	2.11933	2.47237	(0.35304)	(14.3)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,583,051	1,577,379	5,672	0.4				
14. Fuel Cost of Economy Sales (A6)	447,170	2,283,600	(1,836,430)	(80.4)	28,189	162,015	(133,826)	(82.6)	1.58633	1.40950	0.17683	12.5
15. Gain on Economy Sales - 80% (A6)	53,532	698,080	(644,548)	(92.3)	28,189 (a)	162,015 (a)	(133,826)	(82.6)	0.18990	0.43087	(0.24097)	(55.9)
16. Fuel Cost of Sch. D Separ. Sales (A6)	330,378	483,000	(152,622)	(31.6)	31,947	31,282	665	2.1	1.03414	1.54402	(0.50988)	(33.0)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	102,926	90,500	12,426	13.7	5,157	5,711	(554)	(9.7)	1.99585	1.58466	0.41119	25.9
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	0	5,100	(5,100)	(100.0)	0	316	(316)	(100.0)	0.00000	1.61392	(1.61392)	(100.0)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	475,936	150,900	325,036	215.4	23,333	6,455	16,878	261.5	2.03975	2.33772	(0.29797)	(12.7)
21. Fuel Cost of Other Power Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	1,409,942	3,711,180	(2,301,238)	(62.0)	88,626	205,779	(117,153)	(56.9)	1.59089	1.80348	(0.21259)	(11.8)
23. Net Inadvertant Interchange					518	0	518	0.0				
24. Wheeling Rec'd. less Wheeling Del'v'd.					1,237	0	1,237	0.0				
25. Interchange and Wheeling Losses					2,072	3,100	(1,028)	(33.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	32,248,665	30,260,586	1,988,079	6.6	1,494,108	1,368,500	125,608	9.2	2.15839	2.21122	(0.05283)	(2.4)
27. Net Unbilled	(610,285) (a)	(1,562,050) (a)	951,765	(60.9)	(28,275)	(70,642)	42,367	(60.0)	(0.04085)	(0.11414)	0.07329	(64.2)
28. Company Use	85,731 (a)	75,181 (a)	10,550	14.0	3,972	3,400	572	16.8	0.00589	0.00550	0.00039	7.1
29. T & D Losses	1,346,900 (a)	1,501,065 (a)	(154,165)	(10.3)	62,403	67,884	(5,481)	(8.1)	0.09251	0.10974	(0.01723)	(15.7)
30. System KWH Sales	32,248,665	30,260,586	1,988,079	6.6	1,456,008	1,367,858	88,150	6.4	2.21487	2.21226	0.00261	0.1
31. Wholesale KWH Sales	(318,032)	(125,966)	(192,066)	152.5	(14,359)	(5,694)	(8,665)	152.2	2.21486	2.21226	0.00260	0.1
32. Jurisdictional KWH Sales	31,930,633	30,134,620	1,796,013	6.0	1,441,649	1,362,164	79,485	5.8	2.21487	2.21226	0.00261	0.1
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	31,934,784	30,138,538	1,796,246	6.0	1,441,649	1,362,164	79,485	5.8	2.21516	2.21255	0.00261	0.1
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	409,848	412,207	(2,359)	(0.6)	1,441,649	1,362,164	79,485	5.8	0.02843	0.03026	(0.00183)	(6.0)
36. Adjustment - Oil Below the Discharge Valve	(4,922)	0	(4,922)	0.0	1,441,649	1,362,164	79,485	5.8	*(0.00034)*	*0.00000*	*(0.00034)*	*0.0*
37. True-up *	(1,334,790)	(1,334,790)	0	0.0	1,441,649	1,362,164	79,485	5.8	(0.09259)	(0.09799)	0.00540	(5.5)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	31,004,920	29,215,955	1,788,965	6.1	1,441,649	1,362,164	79,485	5.8	2.15066	2.14482	0.00584	0.3
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.15245	2.14660	0.00585	0.3
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,441,649	1,362,164	79,485	5.8	*(0.00420)*	*(0.00445)*	*0.00025*	*(5.6)*
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	30,944,329	29,155,364	1,788,965	6.1	1,441,649	1,362,164	79,485	5.8	2.14825	2.14215	0.00610	0.3
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.148	2.142	0.006	0.3

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	30,784,277	32,515,966	(1,731,689)	(5.3)	30,784,277	32,515,966	(1,731,689)	(5.3)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	1,409,942	3,711,180	(2,301,238)	(62.0)	1,409,942	3,711,180	(2,301,238)	(62.0)
3. FUEL COST OF PURCHASED POWER	2,103,971	718,700	1,385,271	192.7	2,103,971	718,700	1,385,271	192.7
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	697,628	693,200	4,428	0.6	697,628	693,200	4,428	0.6
4. ENERGY COST OF ECONOMY PURCHASES	74,879	46,900	27,979	59.7	74,879	46,900	27,979	59.7
5. TOTAL FUEL & NET POWER TRANSACTION	32,250,813	30,263,586	1,987,227	6.6	32,250,813	30,263,586	1,987,227	6.6
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(2,148)	(3,000)	852	(28.4)	(2,148)	(3,000)	852	(28.4)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	32,248,665	30,260,586	1,988,079	6.6	32,248,665	30,260,586	1,988,079	6.6
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,441,649	1,362,164	79,485	5.8	1,441,649	1,362,164	79,485	5.8
2. NONJURISDICTIONAL SALES	14,359	5,694	8,665	152.2	14,359	5,694	8,665	152.2
3. TOTAL SALES	1,456,008	1,367,858	88,150	6.4	1,456,008	1,367,858	88,150	6.4
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9901381	0.9958373	(0.0056992)	(0.6)	0.9901381	0.9958373	(0.0056992)	(0.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

C. TRUE-UP CALCULATION	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
1. JURISDICTIONAL FUEL REVENUE	33,396,278	30,365,796	3,030,482	10.0	33,396,278	30,365,796	3,030,482	10.0
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	1,334,790	1,334,790	0	0.0	1,334,790	1,334,790	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	60,591	60,591	0	0.0
c. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	34,791,659	31,761,177	3,030,482	9.5	34,791,659	31,761,177	3,030,482	9.5
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	32,248,665	30,260,586	1,988,079	6.6	32,248,665	30,260,586	1,988,079	6.6
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9901381	0.9958373	(0.0056992)	(0.6)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	31,930,633	30,134,620	1,796,013	6.0	31,930,633	30,134,620	1,796,013	6.0
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	31,934,784	30,138,538	1,796,246	6.0	31,934,784	30,138,538	1,796,246	6.0
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	413,930	413,930	0	0.0	413,930	413,930	0	0.0
6D.(LINE 6C x LINE 5)	409,848	412,207	(2,359)	(0.6)	409,848	412,207	(2,359)	(0.6)
6E. FUEL CREDIT DIFFERENTIAL-FMPA	0	0	0	0.0	0	0	0	0.0
6F. OTHER ADJ.(OIL BELOW DISCHG. VALVE)	(4,922)	0	(4,922)	0.0	(4,922)	0	(4,922)	0.0
6G. JURISDIC. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND ADJUSTMENTS	32,339,710	30,550,745	1,788,965	5.9	32,339,710	30,550,745	1,788,965	5.9
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6G)	2,451,949	1,210,432	1,241,517	102.6	2,451,949	1,210,432	1,241,517	102.6
8. INTEREST PROVISION FOR THE MONTH	33,286	19,711	13,575	68.9	33,286	19,711	13,575	68.9
9. TRUE-UP & INT. PROV. BEG. OF MONTH	7,129,041	3,950,955	3,178,086	80.4	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	53,414	53,414	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(1,334,790)	(1,334,790)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	8,332,900	3,899,722	4,433,178	113.7	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	7,182,455	4,004,369	3,178,086	79.4	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	8,299,614	3,880,011	4,419,603	113.9	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	15,482,069	7,884,380	7,597,689	96.4	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	7,741,035	3,942,190	3,798,845	96.4	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.220	6.000	(0.780)	(13.0)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.100	6.000	(0.900)	(15.0)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	10.320	12.000	(1.680)	(14.0)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.160	6.000	(0.840)	(14.0)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.430	0.500	(0.070)	(14.0)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	33,286	19,711	13,575	68.9	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	698,032	314,280	383,752	122.1	698,032	314,280	383,752	122.1
2	LIGHT OIL	1,449,597	254,253	1,195,344	470.1	1,449,597	254,253	1,195,344	470.1
3	COAL	28,636,648	31,947,433	(3,310,785)	(10.4)	28,636,648	31,947,433	(3,310,785)	(10.4)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	30,784,277	32,515,966	(1,731,689)	(5.3)	30,784,277	32,515,966	(1,731,689)	(5.3)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	21,753	8,737	13,016	149.0	21,753	8,737	13,016	149.0
9	LIGHT OIL	40,697	6,580	34,117	518.5	40,697	6,580	34,117	518.5
10	COAL	1,384,875	1,503,058	(118,183)	(7.9)	1,384,875	1,503,058	(118,183)	(7.9)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,447,325	1,518,375	(71,050)	(4.7)	1,447,325	1,518,375	(71,050)	(4.7)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	45,676	20,162	25,514	126.5	45,676	20,162	25,514	126.5
16	LIGHT OIL (BBL)	73,181	11,692	61,489	525.9	73,181	11,692	61,489	525.9
17	COAL (TON)	634,632	687,231	(52,599)	(7.7)	634,632	687,231	(52,599)	(7.7)
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	288,284	127,446	160,838	126.2	288,284	127,446	160,838	126.2
22	LIGHT OIL	425,248	67,946	357,302	525.9	425,248	67,946	357,302	525.9
23	COAL	14,397,228	15,512,152	(1,114,924)	(7.2)	14,397,228	15,512,152	(1,114,924)	(7.2)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	15,110,760	15,707,544	(596,784)	(3.8)	15,110,760	15,707,544	(596,784)	(3.8)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	1.50	0.58	0.92	-	1.50	0.58	0.92	-
29	LIGHT OIL	2.81	0.43	2.38	-	2.81	0.43	2.38	-
30	COAL	95.69	98.99	(3.30)	-	95.69	98.99	(3.30)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	15.28	15.59	(0.31)	(2.0)	15.28	15.59	(0.31)	(2.0)
36	LIGHT OIL ($/BBL)	19.81	21.75	(1.94)	(8.9)	19.81	21.75	(1.94)	(8.9)
37	COAL ($/TON)	45.12	46.49	(1.37)	(2.9)	45.12	46.49	(1.37)	(2.9)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.42	2.47	(0.05)	(2.0)	2.42	2.47	(0.05)	(2.0)
42	LIGHT OIL	3.41	3.74	(0.33)	(8.8)	3.41	3.74	(0.33)	(8.8)
43	COAL	1.99	2.06	(0.07)	(3.4)	1.99	2.06	(0.07)	(3.4)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	2.04	2.07	(0.03)	(1.4)	2.04	2.07	(0.03)	(1.4)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: OCTOBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	13,253	14,587	(1,334)	(9.1)	13,253	14,587	(1,334)	(9.1)
49	LIGHT OIL	10,449	10,326	123	1.2	10,449	10,326	123	1.2
50	COAL	10,396	10,320	76	0.7	10,396	10,320	76	0.7
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,440	10,345	95	0.9	10,440	10,345	95	0.9
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.21	3.60	(0.39)	(10.8)	3.21	3.60	(0.39)	(10.8)
56	LIGHT OIL	3.56	3.86	(0.30)	(7.8)	3.56	3.86	(0.30)	(7.8)
57	COAL	2.07	2.13	(0.06)	(2.8)	2.07	2.13	(0.06)	(2.8)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.13	2.14	(0.01)	(0.5)	2.13	2.14	(0.01)	(0.5)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: OCTOBER, 1998

SCHEDULE A4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPAB-ILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	34	117	0.5	42.3	30.1	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	34	3102	12.2	100.0	56.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	34	3592	14.2	100.0	56.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	43	3205	10.0	100.0	38.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	4908	9.8	86.9	65.5	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	212	14924	9.4	86.6	51.6	15193	HVY.OIL	35865	6321849	226733.1	509472	3.41	14.21
GAN.#1	114	10205	12.0	34.2	61.2	11777	COAL	5292	22709902	120180.8	250996	2.46	47.43
GAN.#2	108	40403	50.2	84.5	65.6	11510	COAL	20105	23130142	465031.5	953567	2.36	47.43
GAN.#3	155	61998	53.7	82.8	63.6	12026	COAL	36740	20293639	745588.3	1742554	2.81	47.43
GAN.#4	179	68516	51.4	83.8	65.8	11413	COAL	33048	23661680	781971.2	1567445	2.29	47.43
GAN.#5	232	67173	38.9	46.5	68.8	10208	COAL	28014	24476701	685690.3	1328685	1.98	47.43
GAN.#6	392	203578	69.7	82.6	70.5	10369	COAL	87248	24193360	2110822.3	4138114	2.03	47.43
GANNON STA.	1180	451873	51.4	71.2	67.2	10864	COAL	210447	23327890	4909284.4	9981361	2.21	47.43
B.B.#1	431	200057	62.3	74.0	72.4	10510	COAL	93885	22395620	2102612.8	3825532	1.91	40.75
B.B.#2	426	210871	66.4	78.7	72.0	10331	COAL	95497	22812300	2178506.2	3891216	1.85	40.75
B.B.#3	438	211186	64.7	76.6	76.8	10162	COAL	94384	22737460	2146052.4	3845865	1.82	40.75
B.B. 1 - 3	1295	622114	64.5	76.4	73.8	10331	COAL	283766	22649547	6427171.4	11562613	1.86	40.75
B.B.#4	447	206793	62.1	67.1	86.2	9674	COAL	94744	21115469	2000564.0	4988799	2.41	52.66
B.B. STA.	1742	828907	63.9	74.0	76.9	10167	COAL	378510	22265555	8427735.4	16551412	2.00	43.73
SEB-PHIL. #1(HVY OIL)	17	3387	26.7	95.1	82.0	9013	HVY.OIL	4866	6273448	30526.6	93521	2.76	19.22
SEB-PHIL. #2(HVY OIL)	17	3442	27.2	96.5	81.3	9013	HVY.OIL	4945	6273852	31024.2	95039	2.76	19.22
SEB-PHILLIPS TOTAL	34	6829	27.0	95.8	81.7	9013	HVY.OIL	9811	6273652	61550.8	188560	2.76	19.22
POLK COAL	250	104095	55.9	60.6	92.4	10185	COAL	45675	23212000	1060208.1	2103875	2.02	46.06
POLK OIL	245	29328	16.1	23.4	66.1	8395	LGT.OIL	42497	5793618	246211.4	798161	2.72	18.78
POLK TOTAL	250	133423	72.0	84.0	-	9792	-	-	-	1306419.5	2902036	2.18	-
GAN.C.T.#1	17	320	2.5	100.0	57.0	18759	LGT.OIL	1032	5816860	6003.0	21902	6.84	21.22
B.B.C.T.#1	17	384	3.0	42.3	59.4	18253	LGT.OIL	1201	5836137	7009.2	25498	6.64	21.23
B.B.C.T.#2	80	5425	9.1	100.0	55.6	15579	LGT.OIL	14483	5835642	84517.6	307485	5.67	21.23
B.B.C.T.#3	80	5240	8.8	100.0	54.1	15555	LGT.OIL	13968	5835266	81507.0	296551	5.66	21.23
C.T. TOTAL	194	11369	7.9	94.9	55.4	15748	LGT.OIL	30684	5834859	179036.8	651436	5.73	21.23
TOT. COAL (GN,BB,POLK)	3172	1384875	58.6	71.9	74.5	10396	COAL	634632	22685947	14397227.9	28636648	2.07	45.12
SYSTEM	3612	1447325	53.8	74.2	72.2	10440	-	-	-	15110760.0	30784277	2.13	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

			CURRENT MONTH				PERIOD TO DATE			
			ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)									
1	PURCHASES:									
2	UNITS (BBL)		13,086	20,162	(7,076)	(35.1)	13,086	20,162	(7,076)	(35.1)
3	UNIT COST ($/BBL)		18.92	14.77	4.15	28.1	18.92	14.77	4.15	28.1
4	AMOUNT ($)	*	247,627	297,702	(50,075)	(16.8)	247,627	297,702	(50,075)	(16.8)
5	BURNED:									
6	UNITS (BBL)		45,676	20,162	25,514	126.5	45,676	20,162	25,514	126.5
7	UNIT COST ($/BBL)		15.28	15.59	(0.31)	(2.0)	15.28	15.59	(0.31)	(2.0)
8	AMOUNT ($)		698,032	314,280	383,752	122.1	698,032	314,280	383,752	122.1
9	ENDING INVENTORY:									
10	UNITS (BBL)		97,263	127,276	(30,013)	(23.6)	97,263	127,276	(30,013)	(23.6)
11	UNIT COST ($/BBL)		14.68	14.22	0.46	3.2	14.68	14.22	0.46	3.2
12	AMOUNT ($)		1,427,872	1,810,058	(382,186)	(21.1)	1,427,872	1,810,058	(382,186)	(21.1)
13										
14	DAYS SUPPLY:		133	740	(607)	(82.0)	-	-	-	-
	LIGHT OIL (2)									
15	PURCHASES:									
16	UNITS (BBL)		81,987	25,267	56,720	224.5	81,987	25,267	56,720	224.5
17	UNIT COST ($/BBL)		20.68	22.38	(1.70)	(7.6)	20.68	22.38	(1.70)	(7.6)
18	AMOUNT ($)		1,695,266	565,448	1,129,818	199.8	1,695,266	565,448	1,129,818	199.8
19	BURNED:									
20	UNITS (BBL)		73,181	11,692	61,489	525.9	73,181	11,692	61,489	525.9
21	UNIT COST ($/BBL)		19.81	21.75	(1.94)	(8.9)	19.81	21.75	(1.94)	(8.9)
22	AMOUNT ($)		1,449,597	254,253	1,195,344	470.1	1,449,597	254,253	1,195,344	470.1
23	ENDING INVENTORY:									
24	UNITS (BBL)		36,513	76,883	(40,370)	(52.5)	36,513	76,883	(40,370)	(52.5)
25	UNIT COST ($/BBL)		19.22	21.73	(2.51)	(11.6)	19.22	21.73	(2.51)	(11.6)
26	AMOUNT ($)		701,700	1,671,033	(969,333)	(58.0)	701,700	1,671,033	(969,333)	(58.0)
27										
28	DAYS SUPPLY: NORMAL		32	79	(47)	(59.5)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY		5	0	5	ERR	-	-	-	-
	COAL (3)									
30	PURCHASES:									
31	UNITS (TONS)		974,223	737,871	236,352	32.0	974,223	737,871	236,352	32.0
32	UNIT COST ($/TON)		44.42	46.84	(2.42)	(5.2)	44.42	46.84	(2.42)	(5.2)
33	AMOUNT ($)		43,275,378	34,559,474	8,715,904	25.2	43,275,378	34,559,474	8,715,904	25.2
34	BURNED:									
35	UNITS (TONS)		634,632	687,231	(52,599)	(7.7)	634,632	687,231	(52,599)	(7.7)
36	UNIT COST ($/TON)		45.12	46.49	(1.37)	(2.9)	45.12	46.49	(1.37)	(2.9)
37	AMOUNT ($)		28,636,648	31,947,433	(3,310,785)	(10.4)	28,636,648	31,947,433	(3,310,785)	(10.4)
38	ENDING INVENTORY:									
39	UNITS (TONS)		778,112	894,942	(116,830)	(13.1)	778,112	894,942	(116,830)	(13.1)
40	UNIT COST ($/TON)		44.32	46.07	(1.75)	(3.8)	44.32	46.07	(1.75)	(3.8)
41	AMOUNT ($)		34,488,508	41,228,837	(6,740,329)	(16.3)	34,488,508	41,228,837	(6,740,329)	(16.3)
42										
43	DAYS SUPPLY:		36	44	(8)	(18.2)	-	-	-	-
	NATURAL GAS									
44	PURCHASES:									
45	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
48	BURNED:									
49	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:									
53	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
56										
57	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-
	NUCLEAR									
58	BURNED:									
59	UNITS (MMBTU)		0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER, 1998

	OTHER		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

* INCLUDES RECLAIMED OIL BELOW THE DISCHARGE VALVE FOR PHILLIPS STATION OF $4,970.10.

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	12,185
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	12,185

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(19,619)	(416,802)
OTHER USAGE	(1,647)	(33,063)
TOTAL	(21,266)	(449,865)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	27,268
IGNITION #2 OIL	404,617
IGNITION PROPANE	2,871
AERIAL SURVEY ADJ.	84,537
ADDITIVES	212,577
TOTAL	731,870

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF OCTOBER, 1998

SCHEDULE A6
PAGE 1 OF 2

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	162,015.0	0.0	162,015.0	1.537	2.075	2,489,400.00	3,362,000.00	698,080.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,711.0	0.0	5,711.0	1.585	1.585	90,500.00	90,500.00	
VARIOUS	SEPARATED	SCH. -D	31,282.0	0.0	31,282.0	1.544	1.815	483,000.00	567,800.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	6,455.0	0.0	6,455.0	2.338	3.283	150,900.00	211,900.00	
VARIOUS		SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDICTIONAL	SCH. -J	316.0	0.0	316.0	1.614	1.614	5,100.00	5,100.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	205,779.0	0.0	205,779.0	1.564	2.059	3,218,900.00	4,237,300.00	698,080.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(205,800.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						698,080.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	205,779.0	0.0	205,779.0	1.803	2.059	3,711,180.00	4,237,300.00	698,080.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	4,073.0	0.0	4,073.0	1.848	2.219	75,276.87	90,375.19	12,078.66
FLA. PWR. & LIGHT		ECON.-C	7,574.0	0.0	7,574.0	1.744	1.811	132,078.36	137,179.03	4,080.54
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	52.0	0.0	52.0	1.774	2.204	922.48	1,146.06	178.86
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	190.0	0.0	190.0	1.808	2.418	3,434.74	4,594.97	928.18
CITY OF NEW SMYRNA BCH.		ECON.-C	24.0	0.0	24.0	1.831	3.449	439.50	827.77	310.62
ORLANDO UTIL. COMM.		ECON.-C	2,154.0	0.0	2,154.0	1.741	1.905	37,503.34	41,040.80	2,829.97
SEMINOLE ELECTRIC CO-OP		ECON.-C	2,427.0	0.0	2,427.0	1.763	2.170	42,788.63	52,668.61	7,903.98
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	11,353.0	0.0	11,353.0	1.707	1.973	193,752.35	223,955.19	24,162.27
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	82.0	0.0	82.0	1.825	2.521	1,496.88	2,066.91	456.02
NP ENERGY INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	9,607.0	0.0	9,607.0	1.683	1.828	161,679.24	175,610.75	
REEDY CREEK	SEPAR.	SCH. -D	14,900.0	0.0	14,900.0	1.353	1.624	201,597.00	241,976.00	
WAUCHULA	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.353	1.624	50,331.60	60,412.80	
FT. MEADE	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.353	1.624	50,331.60	60,412.80	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	23,333.0	0.0	23,333.0	2.083	2.717	486,026.39	633,957.61	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	4,697.0	246.5	4,450.5	2.067	2.067	92,009.01	92,009.01	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	706.0	0.0	706.0	1.546	1.546	10,916.84	10,916.84	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	63,325.0	63,325.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.		ECON.-C	86.0	0.0	86.0	2.172	2.550	1,868.34	2,192.90	259.65 *
HARDEE POWER PART. TO FLA. PWR.& LT.		ECON.-C	152.0	0.0	152.0	2.531	2.783	3,846.55	4,230.24	306.95 *
HARDEE POWER PART. TO REEDY CREEK		ECON.-C	22.0	0.0	22.0	1.996	2.205	439.10	485.04	36.75 *
HARDEE POWER PART. TO GAINESVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO JACKSONVILLE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *

TAMPA ELECTRIC COMPANY
FOR THE MONTH OF OCTOBER, 1998

(1) SOLD TO			(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
HARDEE POWER PART. TO KISSIMMEE			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO NEW SMYRNA BCH.			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ORLANDO			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO STARKE			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FMPA			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ST. CLOUD			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH			ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
ADJUSTMENTS TO PRIOR MONTHS											
HARDEE POWER PARTNERS	9/98	SEPAR.	CONTRACT	(28,828.0)	0.0	(28,828.0)	2.118	2.758	(610,577.04)	(795,076.24)	
HARDEE POWER PARTNERS	9/98	SEPAR.	CONTRACT	28,828.0	0.0	28,828.0	2.083	2.717	600,487.24	783,256.76	
REEDY CREEK	6/98	SEPAR.	SCH. -D	(14,400.0)	0.0	(14,400.0)	1.498	1.798	(215,712.00)	(258,912.00)	
REEDY CREEK	6/98	SEPAR.	SCH. -D	14,400.0	0.0	14,400.0	1.398	1.678	201,312.00	241,632.00	
REEDY CREEK	7/98	SEPAR.	SCH. -D	(14,880.0)	0.0	(14,880.0)	1.508	1.810	(224,390.40)	(269,328.00)	
REEDY CREEK	7/98	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.368	1.642	203,558.40	244,329.60	
REEDY CREEK	8/98	SEPAR.	SCH. -D	(14,880.0)	0.0	(14,880.0)	1.518	1.822	(225,878.40)	(271,113.60)	
REEDY CREEK	8/98	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.340	1.608	199,392.00	239,270.40	
REEDY CREEK	9/98	SEPAR.	SCH. -D	(14,400.0)	0.0	(14,400.0)	1.518	1.822	(218,592.00)	(262,368.00)	
REEDY CREEK	9/98	SEPAR.	SCH. -D	14,400.0	0.0	14,400.0	1.406	1.687	202,464.00	242,928.00	
WAUCHULA	6/98	SEPAR.	SCH. -D	(3,600.0)	0.0	(3,600.0)	1.498	1.798	(53,928.00)	(64,728.00)	
WAUCHULA	6/98	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.398	1.678	50,328.00	60,408.00	
WAUCHULA	7/98	SEPAR.	SCH. -D	(3,720.0)	0.0	(3,720.0)	1.508	1.810	(56,097.60)	(67,332.00)	
WAUCHULA	7/98	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.368	1.642	50,889.60	61,082.40	
WAUCHULA	8/98	SEPAR.	SCH. -D	(3,720.0)	0.0	(3,720.0)	1.518	1.822	(56,469.60)	(67,778.40)	
WAUCHULA	8/98	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.340	1.608	49,848.00	59,817.60	
WAUCHULA	9/98	SEPAR.	SCH. -D	(3,600.0)	0.0	(3,600.0)	1.518	1.822	(54,648.00)	(65,592.00)	
WAUCHULA	9/98	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.406	1.687	50,616.00	60,732.00	
FT. MEADE	6/98	SEPAR.	SCH. -D	(3,600.0)	0.0	(3,600.0)	1.498	1.798	(53,928.00)	(64,728.00)	
FT. MEADE	6/98	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.398	1.678	50,328.00	60,408.00	
FT. MEADE	7/98	SEPAR.	SCH. -D	(3,720.0)	0.0	(3,720.0)	1.508	1.810	(56,097.60)	(67,332.00)	
FT. MEADE	7/98	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.368	1.642	50,889.60	61,082.40	
FT. MEADE	8/98	SEPAR.	SCH. -D	(3,720.0)	0.0	(3,720.0)	1.518	1.822	(56,469.60)	(67,778.40)	
FT. MEADE	8/98	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.340	1.608	49,848.00	59,817.60	
FT. MEADE	9/98	SEPAR.	SCH. -D	(3,600.0)	0.0	(3,600.0)	1.518	1.822	(54,648.00)	(65,592.00)	
FT. MEADE	9/98	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.406	1.687	50,616.00	60,732.00	
SUB-TOTAL ECONOMY POWER SALES				28,189.0	0.0	28,189.0	1.752	1.989	493,847.14	560,762.71	53,532.45
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.				31,947.0	0.0	31,947.0	1.087	1.246	347,169.84	398,069.95	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.				5,403.0	246.5	5,156.5	1.996	1.996	102,925.85	102,925.85	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.				0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.				23,333.0	0.0	23,333.0	2.040	2.666	475,936.59	622,138.13	
SUB-TOTAL OTHER D POWER SALES				63,325.0	63,325.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS				152,197.0	63,571.5	88,625.5	1.602	1.900	1,419,879.42	1,683,896.64	53,532.45
LESS VARIABLE O & M COSTS									(46,641.43)		
LESS VARIABLE O & M COSTS - HARDEE									(36.40)		
LESS TRANSMISSION COSTS SCH. D (SEP.)									(16,792.10)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-							53,532.45		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-		152,197.0	63,571.5	88,625.5	1.591	1.900	1,409,941.94	1,683,896.64	53,532.45
CURRENT MONTH:											
DIFFERENCE		-		(53,582.0)	63,571.5	(117,153.5)	(0.212)	(0.159)	(2,301,238.06)	(2,553,403.36)	(644,547.55)
DIFFERENCE %		-		(26.0)	0.0	(56.9)	(11.8)	(7.7)	(62.0)	(60.3)	(92.3)
PERIOD TO DATE:											
ACTUAL		-		152,197.0	63,571.5	88,625.5	1.591	1.900	1,409,941.94	1,683,896.64	53,532.45
ESTIMATED		-		205,779.0	0.0	205,779.0	1.803	2.059	3,711,180.00	4,237,300.00	698,080.00
DIFFERENCE		-		(53,582.0)	63,571.5	(117,153.5)	(0.212)	(0.159)	(2,301,238.06)	(2,553,403.36)	(644,547.55)
DIFFERENCE %		-		(26.0)	0.0	(56.9)	(11.8)	(7.7)	(62.0)	(60.3)	(92.3)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $547.44 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF OCTOBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	1,995.0	0.0	1,341.0	654.0	5.153	5.153	33,700.00
HARDEE POWER PARTNERS	IPP	17,948.0	0.0	0.0	17,948.0	3.817	3.817	685,000.00
VARIOUS	OTHER	58,688.0	58,688.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	78,631.0	58,688.0	1,341.0	18,602.0	3.864	3.864	718,700.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	61,014.0	0.0	0.0	61,014.0	2.056	2.056	1,254,385.00
HARDEE PWR. PART.-OTHERS	IPP	260.0	0.0	0.0	260.0	2.318	2.332	6,026.44
FLA. POWER CORP.	SCH.-Ja	1,594.0	0.0	1,473.7	120.3	5.723	5.723	6,885.10
FLA. POWER CORP.	SCH.-Jc	8,476.0	0.0	0.0	8,476.0	3.004	3.004	254,608.85
FLA. POWER & LIGHT	SCH.-Ja	5,707.0	0.0	4,577.3	1,129.7	5.572	5.572	62,947.87
FLA. POWER & LIGHT	SCH.-Jc	14,870.0	0.0	0.0	14,870.0	3.408	3.408	506,717.36
CITY OF LAKELAND	SCH.-Ja	323.0	0.0	323.0	0.0	0.000	0.000	0.00
CITY OF LAKELAND	SCH.-Jc	3,141.0	0.0	0.0	3,141.0	3.573	3.573	112,213.00
ORLANDO UTIL. COMM.	SCH.-Ja	1,005.0	0.0	719.9	285.1	5.007	5.007	14,274.15
ORLANDO UTIL. COMM.	SCH.-Jc	3,902.0	0.0	0.0	3,902.0	3.705	3.705	144,571.50
THE ENERGY AUTHORITY	SCH.-Ja	1,839.0	0.0	1,839.0	0.0	0.000	0.000	0.00
THE ENERGY AUTHORITY	SCH.-Jc	2,103.0	0.0	0.0	2,103.0	3.694	3.694	77,678.12
KISSIMMEE ELEC. UTIL.	SCH.-Jc	800.0	0.0	0.0	800.0	3.350	3.350	26,800.00
PECO	SCH.-Jc	440.0	0.0	0.0	440.0	3.100	3.100	13,640.00
LAKE WORTH UTILITIES	SCH.-Ja	62.0	0.0	62.0	0.0	0.000	0.000	0.00
KOCK ENERGY TRAD.	SCH.-Jc	766.0	0.0	0.0	766.0	4.027	4.027	30,847.29
PECO	OTHER	39,250.0	39,250.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	24,075.0	24,075.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVE 9/98	IPP	(111,093.0)	0.0	0.0	(111,093.0)	2.307	2.307	(2,562,432.57)
HARDEE PWR. PART.-NATIVE 9/98	IPP	111,093.0	0.0	0.0	111,093.0	1.946	1.946	2,162,042.53
OGLETHORPE 8/98	SCH.-Jc	(1,517.0)	0.0	0.0	(1,517.0)	5.584	5.584	(84,715.76)
OGLETHORPE 8/98	SCH.-Jc	1,517.0	0.0	0.0	1,517.0	5.108	5.108	77,481.76
TOTAL		169,627.0	63,325.0	8,994.9	97,307.1	2.162	2.162	2,103,970.64
CURRENT MONTH:								
DIFFERENCE	-	90,996.0	4,637.0	7,653.9	78,705.1	(1.702)	(1.702)	1,385,270.64
DIFFERENCE %	-	115.7	7.9	570.8	423.1	(44.0)	(44.0)	192.7
PERIOD TO DATE:								
ACTUAL	-	169,627.0	63,325.0	8,994.9	97,307.1	2.162	2.162	2,103,970.64
ESTIMATED	-	78,631.0	0.0	1,341.0	77,290.0	0.930	0.930	718,700.00
DIFFERENCE	-	90,996.0	63,325.0	7,653.9	20,017.1	1.232	1.232	1,385,270.64
DIFFERENCE %	-	115.7	0.0	570.8	25.9	132.5	132.5	192.7

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF OCTOBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	38,912.0	0.0	0.0	38,912.0	1.781	1.781	693,200.00
TOTAL	-	38,912.0	0.0	0.0	38,912.0	1.781	1.781	693,200.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	388.0	0.0	0.0	388.0	2.473	2.473	9,594.04
McKAY BAY REFUSE	COGEN.	10,469.0	0.0	0.0	10,469.0	1.840	1.840	192,635.57
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	308.0	0.0	0.0	308.0	2.826	2.826	8,702.63
HILLSBOROUGH COUNTY	COGEN.	20,352.0	0.0	0.0	20,352.0	1.855	1.855	377,438.42
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	285.0	0.0	0.0	285.0	2.796	2.796	7,969.13
FARMLAND HYDRO LP	COGEN.	190.0	0.0	0.0	190.0	2.854	2.854	5,422.89
IMC-AGRICO-S. PIERCE	COGEN.	515.0	0.0	0.0	515.0	2.414	2.414	12,432.52
AUBURNDALE POWER PARTNERS	COGEN.	292.0	0.0	0.0	292.0	1.728	1.728	5,045.33
ORANGE COGENERATION L.P.	COGEN.	3,542.0	0.0	0.0	3,542.0	1.778	1.778	62,967.17
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	102.0	(102.0)	4.752	4.752	(4,847.02)
SUB-TOTAL FOR OCT., 1998	-	36,341.0	0.0	102.0	36,239.0	1.869	1.869	677,360.68
ADJUSTMENTS FOR AUG., 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(10,929.0)	0.0	0.0	(10,929.0)	1.884	1.884	(205,857.86)
		10,929.0	0.0	0.0	10,929.0	1.930	1.930	210,879.75
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(20,140.0)	0.0	0.0	(20,140.0)	1.885	1.885	(379,663.06)
		20,140.0	0.0	0.0	20,140.0	1.932	1.932	389,024.32
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.							
FARMLAND HYDRO LP	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(7,268.0)	0.0	0.0	(7,268.0)	1.874	1.874	(136,228.23)
		7,268.0	0.0	0.0	7,268.0	1.955	1.955	142,112.23
AS AVAILABLE ASSIGNMENT	COGEN.							
SUB-TOTAL FOR AUG., 1998 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	20,267.15
GRAND TOTAL		36,341.0	0.0	102.0	36,239.0	1.925	1.925	697,627.83
CURRENT MONTH:								
DIFFERENCE	-	(2,571.0)	0.0	102.0	(2,673.0)	0.144	0.144	4,427.83
DIFFERENCE %	-	(6.6)	0.0	0.0	(6.9)	8.1	8.1	0.6
PERIOD TO DATE:								
ACTUAL		36,341.0	0.0	102.0	36,239.0	1.925	1.925	697,627.83
ESTIMATED		38,912.0	0.0	0.0	38,912.0	1.781	1.781	693,200.00
DIFFERENCE	-	(2,571.0)	0.0	102.0	(2,673.0)	0.144	0.144	4,427.83
DIFFERENCE %	-	(6.6)	0.0	0.0	(6.9)	8.1	8.1	0.6

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF OCTOBER, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	1,490.0	3.148	46,900.00	4.054	60,400.00	13,500.00
TOTAL	-	1,490.0	3.148	46,900.00	4.054	60,400.00	13,500.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	164.0	2.334	3,827.22	2.965	4,863.36	1,036.14
FLA. PWR. & LIGHT	ECON.-C	669.0	3.575	23,917.52	3.581	23,959.09	41.57
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	41.0	3.883	1,592.09	4.303	1,764.29	172.20
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	99.0	3.510	3,475.21	3.933	3,893.35	418.14
ORLANDO UTIL. COMM.	ECON.-C	261.0	3.459	9,028.75	4.016	10,480.49	1,451.74
SEMINOLE ELECTRIC CO-OP.	ECON.-C	164.0	2.697	4,422.43	3.139	5,148.53	726.10
TALLAHASSEE	ECON.-C	104.0	3.299	3,431.39	4.000	4,159.98	728.59
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	70.0	2.956	2,068.85	3.886	2,720.20	651.35
THE ENERGY AUTHORITY	ECON.-C	608.0	3.809	23,161.25	4.633	28,170.75	5,009.50
ADJUSTMENTS TO SEPTEMBER, 1998							
FLA. PWR. & LIGHT	ECON.-C	(328.0)	3.183	(10,440.19)	3.410	(11,185.57)	(745.38)
FLA. PWR. & LIGHT	ECON.-C	328.0	3.169	10,394.32	3.410	11,185.57	791.25
TOTAL	-	2,180.0	3.435	74,878.84	3.906	85,160.04	10,281.20
CURRENT MONTH:							
DIFFERENCE	-	690.0	0.287	27,978.84	(0.148)	24,760.04	(3,218.80)
DIFFERENCE %	-	46.3	9.1	59.7	(3.7)	41.0	(23.8)
PERIOD TO DATE:							
ACTUAL		2,180.0	3.435	74,878.84	3.906	85,160.04	10,281.20
ESTIMATED		1,490.0	3.148	46,900.00	4.054	60,400.00	13,500.00
DIFFERENCE	-	690.0	0.287	27,978.84	(0.148)	24,760.04	(3,218.80)
DIFFERENCE %	-	46.3	9.1	59.7	(3.7)	41.0	(23.8)

COMMISSION SCHEDULES A1 - A9

SEPTEMBER 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	30,222,826	34,679,220	(4,456,394)	(12.9)	1,455,680	1,652,300	(196,620)	(11.9)	2.07620	2.09885	(0.02265)	(1.1)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,775)	(3,500)	(275)	7.9	1,455,680 (a)	1,652,300 (a)	(196,620)	(11.9)	(0.00026)	(0.00021)	(0.00005)	23.8
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,455,680 (a)	1,652,300 (a)	(196,620)	(11.9)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,455,680 (a)	1,652,300 (a)	(196,620)	(11.9)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	30,219,051	34,675,720	(4,456,669)	(12.9)	1,455,680	1,652,300	(196,620)	(11.9)	2.07594	2.09863	(0.02269)	(1.1)
6. Fuel Cost of Purchased Power - Firm (A7)	3,912,702	1,435,400	2,477,302	172.6	146,995	48,202	98,793	205.0	2.66179	2.97788	(0.31609)	(10.6)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	21,707	312,400	(290,693)	(93.1)	709	7,071	(6,362)	(90.0)	3.06164	4.41805	(1.35641)	(30.7)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	651,899	848,600	(196,701)	(23.2)	33,550	39,973	(6,423)	(16.1)	1.94307	2.12293	(0.17986)	(8.5)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	4,586,308	2,596,400	1,989,908	76.6	181,254	95,246	86,008	90.3	2.53032	2.72599	(0.19567)	(7.2)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,636,934	1,747,546	(110,612)	(6.3)				
14. Fuel Cost of Economy Sales (A6)	523,041	1,046,300	(523,259)	(50.0)	30,127	68,319	(38,192)	(55.9)	1.73612	1.53149	0.20463	13.4
15. Gain on Economy Sales - 80% (A6)	113,969	293,040	(179,071)	(61.1)	30,127 (a)	68,319 (a)	(38,192)	(55.9)	0.37830	0.42893	(0.05063)	(11.8)
16. Fuel Cost of Sch. D Separ. Sales (A6)	518,518	500,800	17,718	3.5	34,240	34,091	149	0.4	1.51436	1.46901	0.04535	3.1
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	100,641	98,700	1,941	2.0	4,512	5,781	(1,269)	(22.0)	2.23052	1.70732	0.52320	30.6
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	248,616	135,500	113,116	83.5	11,885	5,760	6,125	106.3	2.09185	2.35243	(0.26058)	(11.1)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	673,889	225,300	448,589	199.1	28,828	9,433	19,395	205.6	2.33762	2.38842	(0.05080)	(2.1)
21. Fuel Cost of Other Power Sales (A6)	(447)	912,300	(912,747)	(100.0)	0	61,200	(61,200)	(100.0)	0.00000	1.49069	(1.49069)	(100.0)
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,178,227	3,211,940	(1,033,713)	(32.2)	109,592	184,584	(74,992)	(40.6)	1.98758	1.74010	0.24748	14.2
23. Net Inadvertant Interchange					(50)	0	(50)	0.0				
24. Wheeling Rec'd. less Wheeling Dely'd.					774	0	774	0.0				
25. Interchange and Wheeling Losses					797	2,800	(2,003)	(71.5)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	32,627,132	34,060,180	(1,433,048)	(4.2)	1,527,269	1,560,162	(32,893)	(2.1)	2.13631	2.18312	(0.04681)	(2.1)
27. Net Unbilled	(3,077,055) (a)	(1,244,051) (a)	(1,833,004)	147.3	(144,036)	(56,985)	(87,051)	152.8	(0.19786)	(0.08095)	(0.11691)	144.4
28. Company Use	87,589 (a)	82,959 (a)	4,630	5.6	4,100	3,800	300	7.9	0.00563	0.00540	0.00023	4.3
29. T & D Losses	2,394,013 (a)	1,670,523 (a)	723,490	43.3	112,063	76,520	35,543	46.4	0.15394	0.10870	0.04524	41.6
30. System KWH Sales	32,627,132	34,060,180	(1,433,048)	(4.2)	1,555,142	1,536,827	18,315	1.2	2.09802	2.21627	(0.11825)	(5.3)
31. Wholesale KWH Sales	(253,589)	(347,376)	93,787	(27.0)	(12,087)	(15,674)	3,587	(22.9)	2.09803	2.21626	(0.11823)	(5.3)
32. Jurisdictional KWH Sales	32,373,543	33,712,804	(1,339,261)	(4.0)	1,543,055	1,521,153	21,902	1.4	2.09802	2.21627	(0.11825)	(5.3)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	32,377,752	33,717,187	(1,339,435)	(4.0)	1,543,055	1,521,153	21,902	1.4	2.09829	2.21655	(0.11826)	(5.3)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	413,224	412,214	1,010	0.2	1,543,055	1,521,153	21,902	1.4	0.02678	0.02710	(0.00032)	(1.2)
36. Fuel Credit Differential - FMPA Sale	0	(373,992)	373,992	(100.0)	1,543,055	1,521,153	21,902	1.4	0.00000	(0.02459)	0.02459	(100.0)
37. True-up *	(728,851)	(728,851)	0	0.0	1,543,055	1,521,153	21,902	1.4	(0.04723)	(0.04791)	0.00068	(1.4)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	32,062,125	33,026,558	(964,433)	(2.9)	1,543,055	1,521,153	21,902	1.4	2.07783	2.17115	(0.09332)	(4.3)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.07955	2.17295	(0.09340)	(4.3)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,592)	1	0.0	1,543,055	1,521,153	21,902	1.4	(0.00393)	(0.00398)	0.00005	(1.3)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	32,001,534	32,965,966	(964,432)	(2.9)	1,543,055	1,521,153	21,902	1.4	2.07562	2.16897	(0.09335)	(4.3)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.076	2.169	(0.093)	(4.3)

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: SEPTEMBER, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	192,399,511	208,814,406	(16,414,895)	(7.9)	9,332,845	9,808,202	(475,357)	(4.8)	2.06153	2.12898	(0.06745)	(3.2)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(24,614)	(21,000)	(3,614)	17.2	9,332,845 (a)	9,808,202 (a)	(475,357)	(4.8)	(0.00026)	(0.00021)	(0.00005)	23.8
4b. Adjustments to Fuel Cost	0	0	0	0.0	9,332,845 (a)	9,808,202 (a)	(475,357)	(4.8)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	9,332,845 (a)	9,808,202 (a)	(475,357)	(4.8)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	192,374,897	208,793,406	(16,418,509)	(7.9)	9,332,845	9,808,202	(475,357)	(4.8)	2.06127	2.12876	(0.06749)	(3.2)
6. Fuel Cost of Purchased Power - Firm (A7)	20,092,069	10,422,500	9,669,569	92.8	659,137	336,033	323,104	96.2	3.04824	3.10163	(0.05339)	(1.7)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	184,320	1,441,500	(1,257,180)	(87.2)	6,432	33,264	(26,832)	(80.7)	2.86567	4.33351	(1.46784)	(33.9)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	4,196,194	5,457,200	(1,261,006)	(23.1)	230,443	237,749	(7,306)	(3.1)	1.82092	2.29536	(0.47444)	(20.7)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	24,472,583	17,321,200	7,151,383	41.3	896,012	607,046	288,966	47.6	2.73128	2.85336	(0.12208)	(4.3)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					10,228,857	10,415,248	(186,391)	(1.8)				
14. Fuel Cost of Economy Sales (A6)	5,527,371	7,295,500	(1,768,129)	(24.2)	320,628	479,664	(159,036)	(33.2)	1.72392	1.52096	0.20296	13.3
15. Gain on Economy Sales - 80% (A6)	4,933,399	2,214,640	2,718,759	122.8	320,628	479,664 (a)	(159,036)	(33.2)	1.53867	0.46171	1.07696	233.3
16. Fuel Cost of Sch. D Separ. Sales (A6)	2,931,419	2,915,800	15,619	0.5	198,626	198,878	(252)	(0.1)	1.47585	1.46612	0.00973	0.7
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	551,271	534,700	16,571	3.1	28,906	30,734	(1,828)	(5.9)	1.90712	1.73977	0.16735	9.6
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,909	0	2,909	0.0	75	0	75	0.0	3.87867	0.00000	3.87867	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	1,514,082	680,900	833,182	122.4	65,242	28,824	36,418	126.3	2.32072	2.36227	(0.04155)	(1.8)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	5,133,985	2,576,300	2,557,685	99.3	252,047	109,746	142,301	129.7	2.03692	2.34751	(0.31059)	(13.2)
21. Fuel Cost of Other Power Sales (A6)	268,026	5,552,500	(5,284,474)	(95.2)	16,744	373,320	(356,576)	(95.5)	1.60073	1.48733	0.11340	7.6
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	20,862,462	21,770,340	(907,878)	(4.2)	882,268	1,221,166	(338,898)	(27.8)	2.36464	1.78275	0.58189	32.6
23. Net Inadvertant Interchange					(670)	0	(670)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					5,710	0	5,710	0.0				
25. Interchange and Wheeling Losses					14,626	18,600	(3,974)	(21.4)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	195,985,018	204,344,266	(8,359,248)	(4.1)	9,337,003	9,175,482	161,521	1.8	2.09901	2.22707	(0.12806)	(5.8)
27. Net Unbilled	3,295,593 (a)	3,965,031 (a)	(669,438)	(16.9)	157,007	178,038	(21,031)	(11.8)	0.03797	0.04650	(0.00853)	(18.3)
28. Company Use	524,773 (a)	507,772 (a)	17,001	3.3	25,001	22,800	2,201	9.7	0.00605	0.00595	0.00010	1.7
29. T & D Losses	10,005,204 (a)	9,967,942 (a)	37,262	0.4	476,663	447,581	29,082	6.5	0.11529	0.11690	(0.00161)	(1.4)
30. System KWH Sales	195,985,018	204,344,266	(8,359,248)	(4.1)	8,678,332	8,527,063	151,269	1.8	2.25833	2.39642	(0.13809)	(5.8)
31. Wholesale KWH Sales	(2,918,298)	(2,273,623)	(644,675)	28.4	(128,480)	(94,549)	(33,931)	35.9	2.27140	2.40470	(0.13330)	(5.5)
32. Jurisdictional KWH Sales	193,066,720	202,070,643	(9,003,923)	(4.5)	8,549,852	8,432,514	117,338	1.4	2.25813	2.39633	(0.13820)	(5.8)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	193,091,819	202,096,913	(9,005,094)	(4.5)	8,549,852	8,432,514	117,338	1.4	2.25842	2.39664	(0.13822)	(5.8)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	2,496,794	2,509,595	(12,801)	(0.5)	8,549,852	8,432,514	117,338	1.4	0.02920	0.02976	(0.00056)	(1.9)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(2,938,153)	2,924,974	(99.6)	8,549,852	8,432,514	117,338	1.4	(0.00015)	(0.03484)	0.03469	(99.6)
37. True-up *	(4,373,121)	(4,373,121)	0	0.0	8,549,852	8,432,514	117,338	1.4	(0.05115)	(0.05186)	0.00071	(1.4)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	191,202,313	197,295,234	(6,092,921)	(3.1)	8,549,852	8,432,514	117,338	1.4	2.23632	2.33970	(0.10338)	(4.4)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.23818	2.34164	(0.10346)	(4.4)
41. GPIF * (Already Adjusted for Taxes)	(363,546)	(363,547)	1	0.0	8,549,852	8,432,514	117,338	1.4	(0.00425)	(0.00431)	0.00006	(1.4)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	190,838,767	196,931,687	(6,092,920)	(3.1)	8,549,852	8,432,514	117,338	1.4	2.23393	2.33733	(0.10340)	(4.4)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.234	2.337	(0.103)	(4.4)

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	30,222,826	34,679,220	(4,456,394)	(12.9)	192,399,511	208,814,406	(16,414,895)	(7.9)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	2,178,227	3,211,940	(1,033,713)	(32.2)	20,862,462	21,770,340	(907,878)	(4.2)
3. FUEL COST OF PURCHASED POWER	3,912,702	1,435,400	2,477,302	172.6	20,092,069	10,422,500	9,669,569	92.8
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	651,899	848,600	(196,701)	(23.2)	4,196,194	5,457,200	(1,261,006)	(23.1)
4. ENERGY COST OF ECONOMY PURCHASES	21,707	312,400	(290,693)	(93.1)	184,320	1,441,500	(1,257,180)	(87.2)
5. TOTAL FUEL & NET POWER TRANSACTION	32,630,907	34,063,680	(1,432,773)	(4.2)	196,009,632	204,365,266	(8,355,634)	(4.1)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,775)	(3,500)	(275)	7.9	(24,614)	(21,000)	(3,614)	17.2
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. * INCLUDES ECONOMY SALES PROFITS (80%)	32,627,132	34,060,180	(1,433,048)	(4.2)	195,985,018	204,344,266	(8,359,248)	(4.1)
B. MWH SALES								
1. JURISDICTIONAL SALES	1,543,055	1,521,153	21,902	1.4	8,549,852	8,432,514	117,338	1.4
2. NONJURISDICTIONAL SALES	12,087	15,674	(3,587)	(22.9)	128,480	94,549	33,931	35.9
3. TOTAL SALES	1,555,142	1,536,827	18,315	1.2	8,678,332	8,527,063	151,269	1.8
4. JURISDIC. SALES-% TOTAL KWH SALES	0.9922277	0.9898011	0.0024266	0.2	0.9851953	0.9889119	(0.0037166)	(0.4)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	35,770,993	35,560,485	210,508	0.6	197,837,814	197,062,438	775,376	0.4
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,851	728,851	0	0.0	4,373,121	4,373,121	0	0.0
b. INCENTIVE PROVISION	60,591	60,592	(1)	0.0	363,546	363,547	(1)	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	36,560,435	36,349,928	210,507	0.6	202,574,481	201,799,106	775,375	0.4
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	32,627,132	34,060,180	(1,433,048)	(4.2)	195,985,018	204,344,266	(8,359,248)	(4.1)
5. JURISDIC. SALES- % TOTAL KWH SALES (LINE B-4)	0.9922277	0.9898011	0.0024266	0.2	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	32,373,543	33,712,804	(1,339,261)	(4.0)	193,066,720	202,070,643	(9,003,923)	(4.5)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	32,377,752	33,717,187	(1,339,435)	(4.0)	193,091,819	202,096,913	(9,005,094)	(4.5)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	416,461	416,461	0	0.0	2,533,731	2,536,731	(3,000)	(0.1)
6D.(LINE 6C x LINE 5)	413,224	412,214	1,010	0.2	2,496,794	2,509,595	(12,801)	(0.5)
6E. INTEREST ON SEPT. 97 ADJ. ON FUEL CREDIT DIFFERENTIAL-FMPA/LKL SALE	0	0	0	0.0	0	0	0	0.0
6F. FUEL CREDIT DIFFERENTIAL-FMPA SALE	0	(373,992)	373,992	0.0	(13,179)	(2,938,153)	2,924,974	(99.6)
6G. REVENUE REFUND TRUE-UP ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
6H. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6I. TRANSMISSION ADJ. (JAN.-NOV. 97)	0	0	0	0.0	0	0	0	0.0
6J. JURISDIC. TOTAL FUEL & NET PWR. INCL. ALL ADJUSTMENTS	32,790,976	33,755,409	(964,433)	(2.9)	195,575,434	201,668,355	(6,092,921)	(3.0)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6J)	3,769,459	2,594,519	1,174,940	45.3	6,999,047	130,751	6,868,296	5,253.0
8. INTEREST PROVISION FOR THE MONTH	25,253	(3,791)	29,044	(766.1)	129,994	40,038	89,956	224.7
9. TRUE-UP & INT. PROV. BEG. OF MONTH	10,159,001	4,351,319	5,807,682	133.5	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,851)	(728,851)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	7,182,455	170,789	7,011,666	4,105.5	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	4,116,594	(1,691,088)	5,807,682	(343.4)	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	7,157,202	174,580	6,982,622	3,999.7	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	11,273,796	(1,516,508)	12,790,304	(843.4)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	5,636,898	(758,254)	6,395,152	(843.4)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.520	6.000	(0.480)	(8.0)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.220	6.000	(0.780)	(13.0)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	10.740	12.000	(1.260)	(10.5)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.370	6.000	(0.630)	(10.5)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.448	0.500	(0.052)	(10.4)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	25,253	(3,791)	29,044	(766.1)	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	851,489	416,946	434,543	104.2	6,490,084	4,247,044	2,243,040	52.8
2	LIGHT OIL	776,335	717,254	59,081	8.2	4,703,743	4,799,057	(95,314)	(2.0)
3	COAL	28,595,002	33,545,020	(4,950,018)	(14.8)	181,205,684	199,768,305	(18,562,621)	(9.3)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	30,222,826	34,679,220	(4,456,394)	(12.9)	192,399,511	208,814,406	(16,414,895)	(7.9)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	23,372	9,375	13,997	149.3	177,254	95,761	81,493	85.1
9	LIGHT OIL	21,097	16,849	4,248	25.2	122,931	104,918	18,013	17.2
10	COAL	1,411,211	1,626,076	(214,865)	(13.2)	9,032,660	9,607,523	(574,863)	(6.0)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,455,680	1,652,300	(196,620)	(11.9)	9,332,845	9,808,202	(475,357)	(4.8)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	57,140	21,603	35,537	164.5	396,202	222,945	173,257	77.7
16	LIGHT OIL (BBL)	42,470	26,672	15,798	59.2	235,440	176,257	59,183	33.6
17	COAL (TON)	651,829	726,143	(74,314)	(10.2)	4,282,240	4,318,588	(36,348)	(0.8)
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	360,770	136,554	224,216	164.2	2,501,151	1,409,238	1,091,913	77.5
22	LIGHT OIL	247,144	154,478	92,666	60.0	1,363,436	1,021,692	341,744	33.4
23	COAL	14,823,813	16,658,214	(1,834,401)	(11.0)	95,362,427	98,663,705	(3,301,278)	(3.3)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	15,431,727	16,949,246	(1,517,519)	(9.0)	99,227,014	101,094,635	(1,867,621)	(1.8)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	1.61	0.57	1.04	-	1.90	0.98	0.92	-
29	LIGHT OIL	1.45	1.02	0.43	-	1.32	1.07	0.25	-
30	COAL	96.94	98.41	(1.47)	-	96.78	97.95	(1.17)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	14.90	19.30	(4.40)	(22.8)	16.38	19.05	(2.67)	(14.0)
36	LIGHT OIL ($/BBL)	18.28	26.89	(8.61)	(32.0)	19.98	27.23	(7.25)	(26.6)
37	COAL ($/TON)	43.87	46.20	(2.33)	(5.0)	42.32	46.26	(3.94)	(8.5)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.36	3.05	(0.69)	(22.6)	2.59	3.01	(0.42)	(14.0)
42	LIGHT OIL	3.14	4.64	(1.50)	(32.3)	3.45	4.70	(1.25)	(26.6)
43	COAL	1.93	2.01	(0.08)	(4.0)	1.90	2.02	(0.12)	(5.9)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.96	2.05	(0.09)	(4.4)	1.94	2.07	(0.13)	(6.3)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: SEPTEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	15,436	14,566	870	6.0	14,111	14,716	(605)	(4.1)
49	LIGHT OIL	11,715	9,168	2,547	27.8	11,091	9,738	1,353	13.9
50	COAL	10,504	10,244	260	2.5	10,558	10,269	289	2.8
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,601	10,258	343	3.3	10,632	10,307	325	3.2
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.64	4.45	(0.81)	(18.2)	3.66	4.44	(0.78)	(17.6)
56	LIGHT OIL	3.68	4.26	(0.58)	(13.6)	3.83	4.57	(0.74)	(16.2)
57	COAL	2.03	2.06	(0.03)	(1.5)	2.01	2.08	(0.07)	(3.4)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.08	2.10	(0.02)	(1.0)	2.06	2.13	(0.07)	(3.3)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: SEPTEMBER, 1998

SCHEDULE A4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	834	3.6	97.8	40.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	4265	18.5	100.0	62.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	3238	14.1	82.4	57.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	4380	14.8	100.0	44.4	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	4066	8.4	70.9	63.2	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	16783	11.4	87.3	54.7	17936	HVY.OIL	47615	6321808	301012.9	674275	4.02	14.16
GAN.#1	114	30095	36.7	54.7	55.2	11548	COAL	15035	23115863	347547.0	734041	2.44	48.82
GAN.#2	108	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	155	42369	38.0	50.6	59.8	11464	COAL	23237	20903120	485725.8	1134481	2.68	48.82
GAN.#4	169	73648	60.5	86.0	65.3	11454	COAL	36053	23397121	843536.4	1760186	2.39	48.82
GAN.#5	227	110289	67.5	82.7	67.5	10394	COAL	47742	24012000	1146380.9	2330868	2.11	48.82
GAN.#6	362	171084	65.6	74.4	65.6	10280	COAL	72653	24207221	1758727.2	3547078	2.07	48.82
GANNON STA.	1135	427485	52.3	65.5	57.9	10718	COAL	194720	23530800	4581917.3	9506654	2.22	48.82
B.B.#1	421	210276	69.4	83.8	70.3	10845	COAL	100761	22632100	2280433.0	4060437	1.93	40.30
B.B.#2	416	232449	77.6	97.0	77.6	10167	COAL	104183	22684460	2363335.1	4198336	1.81	40.30
B.B.#3	428	193709	62.9	74.1	77.2	10673	COAL	91751	22532579	2067386.7	3697355	1.91	40.30
B.B. 1 - 3	1265	636434	69.9	84.9	75.0	10545	COAL	296695	22619710	6711154.8	11956128	1.88	40.30
B.B.#4	442	225465	70.8	78.0	83.3	10214	COAL	106895	21543072	2302846.7	4625028	2.05	43.27
B.B. STA.	1707	861899	70.1	83.1	77.2	10458	COAL	403590	22334551	9014001.5	16581156	1.92	41.08
SEB-PHIL. #1(HVY OIL)	17	3370	27.5	100.0	81.0	9069	HVY.OIL	4872	6273112	30562.6	90644	2.69	18.61
SEB-PHIL. #2(HVY OIL)	17	3219	26.3	95.0	80.2	9070	HVY.OIL	4653	6274404	29194.8	86570	2.69	18.61
SEB-PHILLIPS TOTAL	34	6589	26.9	97.5	80.6	9069	HVY.OIL	9525	6273743	59757.4	177214	2.69	18.61
POLK COAL	250	121827	67.7	71.9	94.1	10079	COAL	53519	22943142	1227894.0	2507192	2.06	46.85
POLK OIL	225	11349	7.0	10.8	64.9	8123	LGT.OIL	15847	5817227	92185.6	308841	2.72	19.49
POLK TOTAL	250	133176	74.7	82.7	-	9912	-	-	-	1320079.6	2816033	2.11	-
GAN.C.T.#1	15	137	1.3	23.3	65.2	19431	LGT.OIL	458	5812445	2662.1	8034	5.86	17.54
B.B.C.T.#1	15	531	4.9	97.8	70.8	18300	LGT.OIL	1671	5815260	9717.3	29343	5.53	17.56
B.B.C.T.#2	65	4725	10.1	100.0	64.9	15249	LGT.OIL	12378	5820973	72052.0	217359	4.60	17.56
B.B.C.T.#3	65	4355	9.3	82.4	59.8	16195	LGT.OIL	12116	5820989	70527.1	212758	4.89	17.56
C.T. TOTAL	160	9748	8.5	85.5	63.4	15896	LGT.OIL	26623	5820475	154958.5	467494	4.80	17.56
TOT.COAL(GN,BB,POLK)	3092	1411211	63.4	75.7	71.5	10504	COAL	651829	22741874	14823812.8	28595002	2.03	43.87
SYSTEM	3490	1455680	57.9	77.1	70.2	10601	-	-	-	15431727.2	30222826	2.08	-

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
SEB-PHIL. = SEBRING-PHILLIPS
GAN. = GANNON
C.T. = COMBUSTION TURBINE

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

			CURRENT MONTH				PERIOD TO DATE			
			ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)									
1	PURCHASES:									
2	UNITS	(BBL)	4,212	21,603	(17,391)	(80.5)	335,461	222,945	112,516	50.5
3	UNIT COST	($/BBL)	(39.37)	18.04	(57.41)	(318.2)	14.62	17.89	(3.27)	(18.3)
4	AMOUNT	($) *	(165,844)	389,797	(555,641)	(142.5)	4,904,525	3,988,232	916,293	23.0
5	BURNED:									
6	UNITS	(BBL)	57,140	21,603	35,537	164.5	396,202	222,945	173,257	77.7
7	UNIT COST	($/BBL)	14.90	19.30	(4.40)	(22.8)	16.38	19.05	(2.67)	(14.0)
8	AMOUNT	($)	851,489	416,946	434,543	104.2	6,490,084	4,247,044	2,243,040	52.8
9	ENDING INVENTORY:									
10	UNITS	(BBL)	129,853	139,530	(9,677)	(6.9)	129,853	139,530	(9,677)	(6.9)
11	UNIT COST	($/BBL)	14.37	17.82	(3.45)	(19.4)	14.37	17.82	(3.45)	(19.4)
12	AMOUNT	($)	1,866,092	2,486,000	(619,908)	(24.9)	1,866,092	2,486,000	(619,908)	(24.9)
13										
14	DAYS SUPPLY:		392	687	(295)	(42.9)	-	-	-	-
	LIGHT OIL (2)									
15	PURCHASES:									
16	UNITS	(BBL)	45,760	36,972	8,788	23.8	277,287	242,696	34,591	14.3
17	UNIT COST	($/BBL)	16.54	27.08	(10.54)	(38.9)	18.57	27.10	(8.53)	(31.5)
18	AMOUNT	($)	756,998	1,001,130	(244,132)	(24.4)	5,148,169	6,577,698	(1,429,529)	(21.7)
19	BURNED:									
20	UNITS	(BBL)	42,470	26,672	15,798	59.2	235,440	176,257	59,183	33.6
21	UNIT COST	($/BBL)	18.28	26.89	(8.61)	(32.0)	19.98	27.23	(7.25)	(26.6)
22	AMOUNT	($)	776,335	717,254	59,081	8.2	4,703,743	4,799,057	(95,314)	(2.0)
23	ENDING INVENTORY:									
24	UNITS	(BBL)	48,973	60,844	(11,871)	(19.5)	48,973	60,844	(11,871)	(19.5)
25	UNIT COST	($/BBL)	18.50	27.17	(8.67)	(31.9)	18.50	27.17	(8.67)	(31.9)
26	AMOUNT	($)	905,896	1,653,106	(747,210)	(45.2)	905,896	1,653,106	(747,210)	(45.2)
27										
28	DAYS SUPPLY: NORMAL		59	78	(19)	(24.4)	-	-	-	-
29	DAYS SUPPLY: EMERGENCY		7	9	(2)	(22.2)	-	-	-	-
	COAL (3)									
30	PURCHASES:									
31	UNITS	(TONS)	522,627	740,500	(217,873)	(29.4)	4,088,432	4,452,737	(364,305)	(8.2)
32	UNIT COST	($/TON)	43.59	45.89	(2.30)	(5.0)	41.97	45.75	(3.78)	(8.3)
33	AMOUNT	($)	22,781,399	33,981,402	(11,200,003)	(33.0)	171,600,335	203,728,402	(32,128,067)	(15.8)
34	BURNED:									
35	UNITS	(TONS)	651,829	726,143	(74,314)	(10.2)	4,282,240	4,318,588	(36,348)	(0.8)
36	UNIT COST	($/TON)	43.87	46.20	(2.33)	(5.0)	42.32	46.26	(3.94)	(8.5)
37	AMOUNT	($)	28,595,002	33,545,020	(4,950,018)	(14.8)	181,205,684	199,768,305	(18,562,621)	(9.3)
38	ENDING INVENTORY:									
39	UNITS	(TONS)	438,521	662,498	(223,977)	(33.8)	438,521	662,498	(223,977)	(33.8)
40	UNIT COST	($/TON)	43.60	45.77	(2.17)	(4.7)	43.60	45.77	(2.17)	(4.7)
41	AMOUNT	($)	19,117,908	30,321,591	(11,203,683)	(36.9)	19,117,908	30,321,591	(11,203,683)	(36.9)
42										
43	DAYS SUPPLY:		21	31	(10)	(32.3)	-	-	-	-
	NATURAL GAS									
44	PURCHASES:									
45	UNITS	(MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST	($/MCF)	0.00	0.00	0	0.0	0.00	0.00	0	0.0
47	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:									
49	UNITS	(MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST	($/MCF)	0.00	0.00	0	0.0	0.00	0.00	0	0.0
51	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:									
53	UNITS	(MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST	($/MCF)	0.00	0.00	0	0.0	0.00	0.00	0	0.0
55	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
56										
57	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-
	NUCLEAR									
58	BURNED:									
59	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER, 1998

		CURRENT MONTH				PERIOD TO DATE			
	OTHER	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:								
63	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:								
67	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:								
71	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

* Includes August 1998 adjustment to Hookers Point Station of ($214,739).

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	9,546
FUEL ANALYSIS	70
LUBE OIL	0
TOTAL	9,616

(2)RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(19,007)	(333,933)
OTHER USAGE	(1,921)	(36,361)
TOTAL	(20,928)	(370,294)

(3)RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
PROPANE IGNITION	2,237
IGNITION	324,387
FUEL ANALYSIS	19,109
AERIAL SURVEY ADJ.	15,217
ADDITIVES	254,117
TOTAL	615,067

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF SEPTEMBER, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	68,319.0	0.0	68,319.0	1.659	2.195	1,133,100.00	1,499,400.00	293,040.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,781.0	0.0	5,781.0	1.707	1.707	98,700.00	98,700.00	
VARIOUS	SEPARATED	SCH. -D	34,091.0	0.0	34,091.0	1.469	1.710	500,800.00	582,900.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	9,433.0	0.0	9,433.0	2.388	3.197	225,300.00	301,600.00	
LAKELAND/FMPA		SCH. -D	61,200.0	0.0	61,200.0	1.491	1.563	912,300.00	956,600.00	
VARIOUS	JURISDICTIONAL	SCH. -J	5,760.0	0.0	5,760.0	2.352	2.352	135,500.00	135,500.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	184,584.0	0.0	184,584.0	1.628	1.937	3,005,700.00	3,574,700.00	293,040.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(86,800.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						293,040.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	184,584.0	0.0	184,584.0	1.740	1.937	3,211,940.00	3,574,700.00	293,040.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	3,959.0	0.0	3,959.0	1.931	2.305	76,445.65	91,256.58	11,848.74
FLA. PWR. & LIGHT		ECON.-C	1,893.0	0.0	1,893.0	2.155	2.706	40,796.40	51,230.11	8,346.98
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	462.0	0.0	462.0	1.773	2.444	8,190.95	11,292.94	2,481.59
CITY OF HOMESTEAD		ECON.-C	205.0	0.0	205.0	1.811	2.311	3,711.71	4,737.39	820.54
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	325.0	0.0	325.0	1.935	3.112	6,289.69	10,113.52	3,059.06
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	415.0	0.0	415.0	1.891	2.194	7,849.59	9,105.29	1,004.56
SEMINOLE ELECTRIC CO-OP		ECON.-C	4,417.0	0.0	4,417.0	1.832	2.240	80,917.79	98,941.86	14,419.26
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	33.0	0.0	33.0	1.876	2.719	619.02	897.33	222.65
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	78.0	0.0	78.0	1.839	1.901	1,434.63	1,483.02	38.71
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	13,802.0	0.0	13,802.0	1.768	2.020	244,077.09	278,831.67	27,803.66
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENERGY, INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	1,600.0	0.0	1,600.0	1.992	4.618	31,877.00	73,881.63	33,603.70
TENNESSEE VALLEY AUTHORITY		ECON.-C	400.0	0.0	400.0	2.694	3.726	10,776.00	14,904.97	3,303.18
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	12,640.0	0.0	12,640.0	1.669	1.816	210,985.56	229,485.28	
REEDY CREEK	SEPAR.	SCH. -D	14,400.0	0.0	14,400.0	1.518	1.822	218,592.00	262,368.00	
WAUCHULA	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.518	1.822	54,648.00	65,592.00	
FT. MEADE	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.518	1.822	54,648.00	65,592.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	CONTRACT	SCH. -D	28,828.0	0.0	28,828.0	2.118	2.758	610,577.04	795,076.24	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	4,188.0	317.2	3,870.8	2.302	2.302	89,109.42	89,109.42	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	641.0	0.0	641.0	1.799	1.799	11,531.70	11,531.70	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	7,425.0	0.0	7,425.0	2.259	2.259	167,732.25	167,732.25	
REEDY CREEK	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	4,460.0	0.0	4,460.0	2.340	2.340	104,350.62	104,350.62	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J								

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF SEPTEMBER, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FMPA	SCH. -D	61,200.0	61,200.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	879.0	0.0	879.0	2.303	2.671	20,240.39	23,478.32	2,590.34 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	470.0	0.0	470.0	2.468	2.801	11,601.34	13,162.80	1,249.17 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	286.0	0.0	286.0	2.072	2.302	5,925.99	6,582.88	525.51 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	217.0	0.0	217.0	2.313	2.775	5,018.20	6,021.94	802.99 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	165.0	0.0	165.0	1.923	2.118	3,173.34	3,493.96	256.50 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO HOMESTEAD	ECON.-C	14.0	0.0	14.0	1.926	2.267	269.66	317.36	38.16 *
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	432.0	0.0	432.0	2.035	2.361	8,789.75	10,200.72	1,128.78 *
HARDEE PWR. PARTNERS TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TALLAHASSEE	ECON.-C	19.0	0.0	19.0	1.705	2.154	323.95	409.23	68.22 *
HARDEE PWR. PARTNERS TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	56.0	0.0	56.0	2.039	2.835	1,141.81	1,587.72	356.73 *
HARDEE PWR. PARTNERS TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ENERGY AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
ADJUSTMENTS TO AUGUST 1998									
HARDEE POWER PARTNERS CONTRACT	SCH. -D	(55,054.0)	0.0	(55,054.0)	2.003	2.639	(1,102,731.62)	(1,452,875.06)	
HARDEE POWER PARTNERS CONTRACT	SCH. -D	55,054.0	0.0	55,054.0	2.118	2.758	1,166,043.72	1,518,389.32	
FLA. PWR. CORP.	C.T. -A	(80.0)	0.0	(80.0)	5.395	5.395	(4,315.85)	(4,315.85)	
FLA. PWR. CORP.	C.T. -A	80.0	0.0	80.0	4.878	4.878	3,902.05	3,902.05	
1997/1998 TRANSM. ADJ. TO VARIOUS CUST.	SCH. -J						(23,466.69)	(23,466.69)	
PRIOR MONTHS TRANSM. ADJ. TO SEMINOLE	SCH. -G						(33.10)	(33.10)	
PRIOR MONTHS TRANSM. ADJ. TO LAKELAND	SCH. -D							(1,864.01)	
SUB-TOTAL ECONOMY POWER SALES		30,127.0	0.0	30,127.0	1.890	2.363	569,469.95	711,931.24	113,969.03
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		34,240.0	0.0	34,240.0	1.574	1.820	538,873.56	623,037.28	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		4,829.0	317.2	4,511.8	2.231	2.231	100,641.12	100,641.12	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		11,885.0	0.0	11,885.0	2.092	2.092	248,616.18	248,616.18	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		28,828.0	0.0	28,828.0	2.338	2.985	673,889.14	860,590.50	
SUB-TOTAL OTHER SCHEDULE D POWER SALES		61,200.0	61,200.0	0.0	0.000	0.000	0.00	(1,864.01)	
SUB-TOTAL OTHER POWER SALES		0.0	0.0	0.0	0.000	0.000	(446.90)	(446.90)	
TOTAL *INCLUDING VARIABLE O & M COSTS*	-	171,109.0	61,517.2	109,591.8	1.945	2.320	2,131,043.05	2,542,505.41	113,969.03
LESS VARIABLE O & M COSTS	-						(46,073.63)		
LESS VARIABLE O & M COSTS - HARDEE	-						(355.32)		
LESS TRANSMISSION COSTS SCH.-D (SEP.)							(20,356.48)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						113,969.03		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	171,109.0	61,517.2	109,591.8	1.988	2.320	2,178,226.65	2,542,505.41	113,969.03
CURRENT MONTH:									
DIFFERENCE	-	(13,475.0)	61,517.2	(74,992.2)	0.248	0.383	(1,033,713.35)	(1,032,194.59)	(179,070.97)
DIFFERENCE %	-	(7.3)	0.0	(40.6)	14.3	19.8	(32.2)	(28.9)	(61.1)
PERIOD TO DATE:									
ACTUAL	-	1,241,240.0	358,972.7	882,267.3	2.365	2.812	20,862,461.29	24,810,941.93	4,933,398.93
ESTIMATED	-	1,221,166.0	0.0	1,221,166.0	1.783	2.014	21,770,340.00	24,588,500.00	2,214,640.00
DIFFERENCE	-	20,074.0	358,972.7	(338,898.7)	0.582	0.798	(907,878.71)	222,441.93	2,718,758.93
DIFFERENCE %	-	1.6	0.0	(27.8)	32.6	39.6	(4.2)	0.9	122.8

* ONLY TEC 40% REFLECTED HERE. SEC 60% OR $7,456.67 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF SEPTEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	2,844.0	0.0	1,823.0	1,021.0	5.162	5.162	52,700.00
HARDEE POWER PARTNERS	IPP	47,181.0	0.0	0.0	47,181.0	2.931	2.931	1,382,700.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	50,025.0	0.0	1,823.0	48,202.0	2.978	2.978	1,435,400.00
ACTUAL:								
HARDEE POW. PART.-NATIVE	IPP	111,093.0	0.0	0.0	111,093.0	2.307	2.307	2,562,432.57
HARDEE POW. PART.-OTHERS	IPP	2,538.0	0.0	0.0	2,538.0	2.179	2.193	55,292.79
FLA. POWER CORP.	SCH. -Ja	9,481.0	0.0	5,883.9	3,597.1	6.033	6.033	217,014.28
FLA. POWER CORP.	SCH. -Jc	4,067.0	0.0	0.0	4,067.0	2.705	2.705	110,019.75
FLA. PWR. & LIGHT	SCH. -Ja	1,018.0	0.0	1,013.8	4.2	7.275	7.275	305.53
FLA. PWR. & LIGHT	SCH. -Jc	3,926.0	0.0	0.0	3,926.0	3.013	3.013	118,290.00
CITY OF LAKELAND	SCH. -Ja	1,485.0	0.0	1,037.5	447.5	4.650	4.650	20,810.56
CITY OF LAKELAND	SCH. -Jc	7,295.0	0.0	0.0	7,295.0	3.100	3.100	226,139.60
ORLANDO UTIL. COMM.	SCH. -Ja	7,126.0	0.0	1,979.3	5,146.7	5.137	5.137	264,363.86
ORLANDO UTIL. COMM.	SCH. -Jc	4,140.0	0.0	0.0	4,140.0	2.822	2.822	116,835.50
KISSIMMEE ELEC. UTIL.	SCH. -Ja	678.0	0.0	678.0	0.0	0.000	0.000	0.00
KISSIMMEE ELEC. UTIL.	SCH. -Jc	122.0	0.0	0.0	122.0	5.000	5.000	6,100.00
THE ENERGY AUTH.	SCH. -Ja	2,194.0	0.0	1,487.6	706.4	4.792	4.792	33,848.84
THE ENERGY AUTH.	SCH. -Jc	2,797.0	0.0	0.0	2,797.0	4.170	4.170	116,632.51
REEDY CREEK	SCH. -Ja	40.0	0.0	40.0	0.0	0.000	0.000	0.00
PECO	SCH. -Ja	879.0	0.0	488.0	391.0	4.836	4.836	18,908.53
PECO	SCH. -Jc	724.0	0.0	0.0	724.0	4.738	4.738	34,302.07
KOCK ENERGY TRAD.	SCH. -Ja	980.0	0.0	980.0	0.0	0.000	0.000	0.00
PECO	OTHER	37,950.0	37,950.0	0.0	0.0	0.000	0.000	0.00
FPC	OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO AUGUST 1998								
HARDEE PWR. PART.-NATIVE	IPP	(98,870.0)	0.0	0.0	(98,870.0)	2.523	2.523	(2,494,333.56)
HARDEE PWR. PART.-NATIVE	IPP	98,870.0	0.0	0.0	98,870.0	2.534	2.534	2,505,739.00
TOTAL		221,783.0	61,200.0	13,588.1	146,994.9	2.662	2.662	3,912,701.83
CURRENT MONTH:								
DIFFERENCE	-	171,758.0	61,200.0	11,765.1	98,792.9	(0.316)	(0.316)	2,477,301.83
DIFFERENCE %	-	343.3	0.0	645.4	205.0	(10.6)	(10.6)	172.6
PERIOD TO DATE:								
ACTUAL	-	1,099,925.0	356,571.0	84,216.8	659,137.2	3.048	3.055	20,092,069.19
ESTIMATED	-	354,752.0	0.0	18,719.0	336,033.0	3.102	3.102	10,422,500.00
DIFFERENCE	-	745,173.0	356,571.0	65,497.8	323,104.2	(0.054)	(0.047)	9,669,569.19
DIFFERENCE %	-	210.1	0.0	349.9	96.2	(1.7)	(1.5)	92.8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF SEPTEMBER, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	39,973.0	0.0	0.0	39,973.0	2.123	2.123	848,600.00
TOTAL	-	39,973.0	0.0	0.0	39,973.0	2.123	2.123	848,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	647.0	0.0	0.0	647.0	2.555	2.555	16,528.99
McKAY BAY REFUSE	COGEN.	9,697.0	0.0	0.0	9,697.0	1.904	1.904	184,655.03
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	31.0	0.0	0.0	31.0	4.307	4.307	1,335.02
HILLSBOROUGH COUNTY	COGEN.	15,101.0	0.0	0.0	15,101.0	1.896	1.896	286,376.25
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	472.0	0.0	0.0	472.0	2.252	2.252	10,627.54
FARMLAND HYDRO LP	COGEN.	90.0	0.0	0.0	90.0	3.327	3.327	2,994.33
IMC-AGRICO-S. PIERCE	COGEN.	433.0	0.0	0.0	433.0	2.515	2.515	10,891.36
AUBURNDALE POWER PARTNERS	COGEN.	59.0	0.0	0.0	59.0	1.815	1.815	1,070.81
ORANGE COGENERATION L.P.	COGEN.	7,153.0	0.0	0.0	7,153.0	1.920	1.920	137,355.92
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	133.0	(133.0)	4.960	4.960	(6,596.78)
SUB-TOTAL FOR SEPTEMBER, 1998	-	33,683.0	0.0	133.0	33,550.0	1.923	1.923	645,238.47
ADJUSTMENTS FOR JULY, 1998								
IMC-AGRICO-NICHOLS	COGEN.	(1,988.0)	0.0	0.0	(1,988.0)	3.743	3.743	(74,414.55)
		1,988.0	0.0	0.0	1,988.0	3.746	3.746	74,479.25
McKAY BAY REFUSE	COGEN.	(9,217.0)	0.0	0.0	(9,217.0)	1.835	1.835	(169,168.17)
		9,217.0	0.0	0.0	9,217.0	1.851	1.851	170,615.40
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(19,171.0)	0.0	0.0	(19,171.0)	1.833	1.833	(351,335.71)
		19,171.0	0.0	0.0	19,171.0	1.848	1.848	354,309.72
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.							
FARMLAND HYDRO LP	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.	(310.0)	0.0	0.0	(310.0)	5.815	5.815	(18,026.50)
		310.0	0.0	0.0	310.0	5.998	5.998	18,592.52
ORANGE COGENERATION L.P.	COGEN.	(6,394.0)	0.0	0.0	(6,394.0)	1.832	1.832	(117,141.61)
		6,394.0	0.0	0.0	6,394.0	1.858	1.858	118,813.18
AS AVAILABLE ASSIGNMENT	COGEN.	1,170.0	0.0	0.0	1,170.0	7.628	7.628	89,244.28
		(1,170.0)	0.0	0.0	(1,170.0)	7.633	7.633	(89,307.38)
SUB-TOTAL FOR JULY, 1998 ADJ.		0.0	0.0	0.0	0.0	0.000	0.000	6,660.43
GRAND TOTAL		33,683.0	0.0	133.0	33,550.0	1.943	1.943	651,898.90
CURRENT MONTH:								
DIFFERENCE	-	(6,290.0)	0.0	133.0	(6,423.0)	(0.180)	(0.180)	(196,701.10)
DIFFERENCE %	-	(15.7)	0.0	0.0	(16.1)	(8.5)	(8.5)	(23.2)
PERIOD TO DATE:								
ACTUAL		233,326.0	0.0	2,882.7	230,443.3	1.821	1.821	4,196,193.72
ESTIMATED		237,749.0	0.0	0.0	237,749.0	2.295	2.295	5,457,200.00
DIFFERENCE	-	(4,423.0)	0.0	2,882.7	(7,305.7)	(0.474)	(0.474)	(1,261,006.28)
DIFFERENCE %	-	(1.9)	0.0	0.0	(3.1)	(20.7)	(20.7)	(23.1)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF SEPTEMBER, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	7,071.0	4.418	312,400.00	5.163	365,100.00	52,700.00
TOTAL	-	7,071.0	4.418	312,400.00	5.163	365,100.00	52,700.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	98.0	2.873	2,815.80	3.715	3,640.76	824.96
FLA. PWR. & LIGHT	ECON.-C	328.0	3.183	10,440.19	3.410	11,185.57	745.38
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	39.0	3.228	1,259.00	3.858	1,504.80	245.80
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	14.0	2.630	368.20	2.710	379.35	11.15
ORLANDO UTIL. COMM.	ECON.-C	30.0	2.999	899.80	3.699	1,109.60	209.80
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	200.0	2.802	5,604.00	3.724	7,448.00	1,844.00
ADJUSTMENTS TO AUGUST 1998:							
FLA. PWR. & LIGHT	ECON.-C	(842.0)	2.765	(23,283.04)	2.771	(23,331.06)	(48.02)
FLA. PWR. & LIGHT	ECON.-C	842.0	2.803	23,602.76	2.771	23,331.06	(271.70)
TOTAL	-	709.0	3.062	21,706.71	3.564	25,268.08	3,561.37
CURRENT MONTH:							
DIFFERENCE	-	(6,362.0)	(1.356)	(290,693.29)	(1.599)	(339,831.92)	(49,138.63)
DIFFERENCE %	-	(90.0)	(30.7)	(93.1)	(31.0)	(93.1)	(93.2)
PERIOD TO DATE:							
ACTUAL		6,432.0	2.866	184,320.91	3.500	225,143.41	40,822.50
ESTIMATED		33,264.0	4.334	1,441,500.00	5.097	1,695,300.00	253,800.00
DIFFERENCE	-	(26,832.0)	(1.468)	(1,257,179.09)	(1.597)	(1,470,156.59)	(212,977.50)
DIFFERENCE %	-	(80.7)	(33.9)	(87.2)	(31.3)	(86.7)	(83.9)

COMMISSION SCHEDULES A1 - A9

AUGUST 1998

SCHEDULE A1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

	$				KWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	35,524,071	37,886,896	(2,362,825)	(6.2)	1,675,688	1,755,996	(80,308)	(4.6)	2.11997	2.15757	(0.03760)	(1.7)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Hauch. Wheeling Losses)	(4,497)	(3,500)	(997)	28.5	1,675,688 (a)	1,755,996 (a)	(80,308)	(4.6)	(0.00027)	(0.00020)	(0.00007)	35.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,675,688 (a)	1,755,996 (a)	(80,308)	(4.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,675,688 (a)	1,755,996 (a)	(80,308)	(4.6)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	35,519,574	37,883,396	(2,363,822)	(6.2)	1,675,688	1,755,996	(80,308)	(4.6)	2.11970	2.15737	(0.03767)	(1.7)
6. Fuel Cost of Purchased Power - Firm (A7)	3,929,738	2,197,000	1,732,738	78.9	139,707	70,119	69,588	99.2	2.81284	3.13324	(0.32040)	(10.2)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	48,680	279,200	(230,520)	(82.6)	2,032	6,371	(4,339)	(68.1)	2.39567	4.38236	(1.98669)	(45.3)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	799,978	980,200	(180,222)	(18.4)	41,352	41,305	47	0.1	1.93456	2.37308	(0.43852)	(18.5)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	4,778,396	3,456,400	1,321,996	38.2	183,091	117,795	65,296	55.4	2.60985	2.93425	(0.32440)	(11.1)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,858,779	1,873,791	(15,012)	(0.8)				
14. Fuel Cost of Economy Sales (A6)	790,584	1,108,200	(317,616)	(28.7)	39,726	74,344	(34,618)	(46.6)	1.99009	1.49064	0.49945	33.5
15. Gain on Economy Sales - 80% (A6)	229,076	337,680	(108,604)	(32.2)	39,726 (a)	74,344 (a)	(34,618)	(46.6)	0.57664	0.45421	0.12243	27.0
16. Fuel Cost of Sch. D Separ. Sales (A6)	524,231	520,300	3,931	0.8	34,614	35,228	(614)	(1.7)	1.51451	1.47695	0.03756	2.5
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	125,740	107,200	18,540	17.3	5,109	5,840	(731)	(12.5)	2.46115	1.83562	0.62553	34.1
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	342,673	140,100	202,573	144.6	13,751	5,952	7,799	131.0	2.49199	2.35383	0.13816	5.9
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	1,101,473	507,200	594,273	117.2	55,054	21,235	33,819	159.3	2.00071	2.38851	(0.38780)	(16.2)
21. Fuel Cost of Other Power Sales (A6)	4,316	950,500	(946,184)	(99.5)	80	63,240	(63,160)	(99.9)	5.39500	1.50300	3.89200	258.9
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	3,118,093	3,671,180	(553,087)	(15.1)	148,334	205,839	(57,505)	(27.9)	2.10208	1.78352	0.31856	17.9
23. Net Inadvertant Interchange					(172)	0	(172)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					4,522	0	4,522	0.0				
25. Interchange and Wheeling Losses					3,616	3,100	516	16.6				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	37,179,877	37,668,616	(488,739)	(1.3)	1,711,179	1,664,852	46,327	2.8	2.17276	2.26258	(0.08982)	(4.0)
27. Net Unbilled	1,534,468 (a)	1,414,271 (a)	120,197	8.5	70,623	62,507	8,116	13.0	0.08967	0.08495	0.00472	5.6
28. Company Use	93,342 (a)	85,978 (a)	7,364	8.6	4,296	3,800	496	13.1	0.00605	0.00567	0.00038	6.7
29. T & D Losses	2,002,046 (a)	1,843,550 (a)	158,496	8.6	92,143	81,480	10,663	13.1	0.12966	0.12152	0.00814	6.7
30. System KWH Sales	37,179,877	37,668,616	(488,739)	(1.3)	1,544,111	1,517,065	27,052	1.8	2.40784	2.48299	(0.07515)	(3.0)
31. Wholesale KWH Sales	(631,575)	(546,730)	(84,845)	15.5	(26,230)	(22,019)	(4,211)	19.1	2.40783	2.48299	(0.07516)	(3.0)
32. Jurisdictional KWH Sales	36,548,302	37,121,886	(573,584)	(1.5)	1,517,881	1,495,046	22,841	1.5	2.40784	2.48299	(0.07515)	(3.0)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	36,553,053	37,126,712	(573,659)	(1.5)	1,517,881	1,495,046	22,841	1.5	2.40815	2.48332	(0.07517)	(3.0)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	411,875	412,911	(1,036)	(0.3)	1,517,881	1,495,046	22,841	1.5	0.02713	0.02762	(0.00049)	(1.8)
36. Fuel Credit Differential - FKPA Sale	0	(533,544)	533,544	(100.0)	1,517,881	1,495,046	22,841	1.5	0.00000	(0.03569)	0.03569	(100.0)
37. True-up *	(728,854)	(728,854)	0	0.0	1,517,881	1,495,046	22,841	1.5	(0.04802)	(0.04875)	0.00073	(1.5)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	36,236,074	36,277,225	(41,151)	(0.1)	1,517,881	1,495,046	22,841	1.5	2.38727	2.42650	(0.03923)	(1.6)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.38925	2.42851	(0.03926)	(1.6)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,517,881	1,495,046	22,841	1.5	(0.00399)	(0.00405)	0.00006	(1.5)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	36,175,483	36,216,634	(41,151)	(0.1)	1,517,881	1,495,046	22,841	1.5	2.38526	2.42446	(0.03920)	(1.6)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.385	2.424	(0.039)	(1.6)

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: AUGUST, 1998

SCHEDULE A1

	$				KWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	162,176,685	174,135,186	(11,958,501)	(6.9)	7,877,165	8,155,902	(278,737)	(3.4)	2.05882	2.13508	(0.07626)	(3.6)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Tauch. Wheeling Losses)	(20,839)	(17,500)	(3,339)	19.1	7,877,165 (a)	8,155,902 (a)	(278,737)	(3.4)	(0.00026)	(0.00021)	(0.00005)	23.8
4b. Adjustments to Fuel Cost	0	0	0	0.0	7,877,165 (a)	8,155,902 (a)	(278,737)	(3.4)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	7,877,165 (a)	8,155,902 (a)	(278,737)	(3.4)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	162,155,846	174,117,686	(11,961,840)	(6.9)	7,877,165	8,155,902	(278,737)	(3.4)	2.05856	2.13487	(0.07631)	(3.6)
6. Fuel Cost of Purchased Power - Firm (A7)	16,179,367	8,987,100	7,192,267	80.0	512,142	287,831	224,311	77.9	3.15916	3.12235	0.03681	1.2
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	162,613	1,129,100	(966,487)	(85.6)	5,723	26,193	(20,470)	(78.2)	2.84139	4.31069	(1.46930)	(34.1)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. X Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. X Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	3,544,295	4,608,600	(1,064,305)	(23.1)	196,893	197,776	(883)	(0.4)	1.80011	2.33021	(0.53010)	(22.7)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	19,886,275	14,724,800	5,161,475	35.1	714,758	511,800	202,958	39.7	2.78224	2.87706	(0.09482)	(3.3)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					8,591,923	8,667,702	(75,779)	(0.9)				
14. Fuel Cost of Economy Sales (A6)	5,004,330	6,249,200	(1,244,870)	(19.9)	290,501	411,345	(120,844)	(29.4)	1.72265	1.51921	0.20344	13.4
15. Gain on Economy Sales - 80% (A6)	4,819,430	1,921,600	2,897,830	150.8	290,501	411,345 (a)	(120,844)	(29.4)	1.65901	0.46715	1.19186	255.1
16. Fuel Cost of Sch. D Separ. Sales (A6)	2,412,901	2,415,000	(2,099)	(0.1)	164,386	164,787	(401)	(0.2)	1.46783	1.46553	0.00230	0.2
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	450,630	436,000	14,630	3.4	24,394	24,953	(559)	(2.2)	1.84730	1.74728	0.10002	5.7
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,909	0	2,909	0.0	75	0	75	0.0	3.87867	0.00000	3.87867	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	1,265,466	545,400	720,066	132.0	53,357	23,064	30,293	131.3	2.37170	2.36472	0.00698	0.3
20. Fuel Cost of NPF Sch. D Separ. Sales (A6)	4,460,096	2,351,000	2,109,096	89.7	223,219	100,313	122,906	122.5	1.99808	2.34366	(0.34558)	(14.7)
21. Fuel Cost of Other Power Sales (A6)	268,473	4,640,200	(4,371,727)	(94.2)	16,744	312,120	(295,376)	(94.6)	1.60340	1.48667	0.11673	7.9
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	18,684,235	18,558,400	125,835	0.7	772,676	1,036,582	(263,906)	(25.5)	2.41812	1.79035	0.62777	35.1
23. Net Inadvertant Interchange					(620)	0	(620)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					4,936	0	4,936	0.0				
25. Interchange and Wheeling Losses					13,829	15,800	(1,971)	(12.5)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	163,357,886	170,284,086	(6,926,200)	(4.1)	7,805,734	7,615,320	194,414	2.6	2.09172	2.23607	(0.14435)	(6.5)
27. Net Unbilled	6,296,977 (a)	5,255,279 (a)	1,041,698	19.8	301,043	235,023	66,020	28.1	0.88063	0.06901	0.01162	16.8
28. Company Use	437,190 (a)	424,853 (a)	12,337	2.9	20,901	19,000	1,901	10.0	0.00614	0.00608	0.00006	1.0
29. T & D Losses	7,626,411 (a)	8,297,184 (a)	(670,773)	(8.1)	364,680	371,061	(6,461)	(1.7)	0.10706	0.11870	(0.01164)	(9.8)
30. System KWH Sales	163,357,886	170,284,086	(6,926,200)	(4.1)	7,123,190	6,990,236	132,954	1.9	2.29332	2.43603	(0.14271)	(5.9)
31. Wholesale KWH Sales	(2,664,709)	(1,926,247)	(738,462)	38.3	(116,393)	(78,875)	(37,518)	47.6	2.28941	2.44215	(0.15274)	(6.3)
32. Jurisdictional KWH Sales	160,693,177	168,357,839	(7,664,662)	(4.6)	7,006,797	6,911,361	95,436	1.4	2.29339	2.43596	(0.14257)	(5.9)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	160,714,067	168,379,726	(7,665,659)	(4.6)	7,006,797	6,911,361	95,436	1.4	2.29369	2.43627	(0.14258)	(5.9)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	2,083,570	2,097,381	(13,811)	(0.7)	7,006,797	6,911,361	95,436	1.4	0.02974	0.03035	(0.00061)	(2.0)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(2,564,161)	2,550,982	(99.5)	7,006,797	6,911,361	95,436	1.4	(0.00019)	(0.03710)	0.03691	(99.5)
37. True-up *	(3,644,270)	(3,644,270)	0	0.0	7,006,797	6,911,361	95,436	1.4	(0.05201)	(0.05273)	0.00072	(1.4)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	159,140,188	164,268,676	(5,128,488)	(3.1)	7,006,797	6,911,361	95,436	1.4	2.27123	2.37679	(0.10556)	(4.4)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.27312	2.37876	(0.10564)	(4.4)
41. GPIF * (Already Adjusted for Taxes)	(302,955)	(302,955)	0	0.0	7,006,797	6,911,361	95,436	1.4	(0.00432)	(0.00438)	0.00006	(1.4)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	158,837,233	163,965,721	(5,128,488)	(3.1)	7,006,797	6,911,361	95,436	1.4	2.26880	2.37438	(0.10558)	(4.4)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.269	2.374	(0.105)	(4.4)

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,524,071	37,886,896	(2,362,825)	(6.2)	162,176,685	174,135,186	(11,958,501)	(6.9)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	3,118,093	3,671,180	(553,087)	(15.1)	18,684,235	18,558,400	125,835	0.7
3. FUEL COST OF PURCHASED POWER	3,929,738	2,197,000	1,732,738	78.9	16,179,367	8,987,100	7,192,267	80.0
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	799,978	980,200	(180,222)	(18.4)	3,544,295	4,608,600	(1,064,305)	(23.1)
4. ENERGY COST OF ECONOMY PURCHASES	48,680	279,200	(230,520)	(82.6)	162,613	1,129,100	(966,487)	(85.6)
5. TOTAL FUEL & NET POWER TRANSACTION	37,184,374	37,672,116	(487,742)	(1.3)	163,378,725	170,301,586	(6,922,861)	(4.1)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,497)	(3,500)	(997)	28.5	(20,839)	(17,500)	(3,339)	19.1
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	37,179,877	37,668,616	(488,739)	(1.3)	163,357,886	170,284,086	(6,926,200)	(4.1)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,517,887	1,495,046	22,841	1.5	7,006,797	6,911,361	95,436	1.4
2. NONJURISDICTIONAL SALES	26,230	22,019	4,211	19.1	116,393	78,875	37,518	47.6
3. TOTAL SALES	1,544,117	1,517,065	27,052	1.8	7,123,190	6,990,236	132,954	1.9
4. JURISDIC. SALES-% TOTAL KWH SALES	0.9830129	0.9854858	(0.0024729)	(0.3)	0.9836600	0.9887164	(0.0050564)	(0.5)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	35,096,546	34,948,992	147,554	0.4	162,066,821	161,501,953	564,868	0.3
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,854	728,854	0	0.0	3,644,270	3,644,270	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	302,955	302,955	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,885,991	35,738,437	147,554	0.4	166,014,046	165,449,178	564,868	0.3
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	37,179,877	37,668,616	(488,739)	(1.3)	163,357,886	170,284,086	(6,926,200)	(4.1)
5. JURISDIC. SALES- % TOTAL KWH SALES (LINE B-4)	0.9830129	0.9854858	(0.0024729)	(0.3)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	36,548,302	37,121,886	(573,584)	(1.5)	160,693,177	168,357,839	(7,664,662)	(4.6)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	36,553,053	37,126,712	(573,659)	(1.5)	160,714,067	168,379,726	(7,665,659)	(4.6)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	418,992	418,992	0	0.0	2,117,270	2,120,270	(3,000)	(0.1)
6D.(LINE 6C x LINE 5)	411,875	412,911	(1,036)	(0.3)	2,083,570	2,097,381	(13,811)	(0.7)
6E. INTEREST ON SEPT. 97 ADJ. ON FUEL CREDIT DIFFERENTIAL-FMPA/LKL SALE	0	0	0	0.0	0	0	0	0.0
6F. FUEL CREDIT DIFFERENTIAL-FMPA SALE	0	(533,544)	533,544	0.0	(13,179)	(2,564,161)	2,564,161	0.0
6G. REVENUE REFUND TRUE-UP ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
6H. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6I. TRANSMISSION ADJ. (JAN.-NOV. 97)	0	0	0	0.0	0	0	0	0.0
6J. JURISDIC. TOTAL FUEL & NET PWR. INCL. ALL ADJUSTMENTS	36,964,928	37,006,079	(41,151)	(0.1)	162,784,458	167,912,946	(5,128,488)	(3.1)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6J)	(1,078,937)	(1,267,642)	188,705	(14.9)	3,229,588	(2,463,768)	5,693,356	(231.1)
8. INTEREST PROVISION FOR THE MONTH	23,088	(3,447)	26,535	(769.8)	104,741	43,829	60,912	139.0
9. TRUE-UP & INT. PROV. BEG. OF MONTH	11,943,704	6,351,262	5,592,442	88.1	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,854)	(728,854)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	4,116,594	(1,691,088)	5,807,682	(343.4)	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	5,901,297	308,855	5,592,442	1,810.7	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	4,093,506	(1,687,641)	5,781,147	(342.6)	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	9,994,803	(1,378,786)	11,373,589	(824.9)	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	4,997,402	(689,393)	5,686,795	(824.9)	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.560	6.000	(0.440)	(7.3)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.520	6.000	(0.480)	(8.0)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.080	12.000	(0.920)	(7.7)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.540	6.000	(0.460)	(7.7)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.462	0.500	(0.038)	(7.6)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	23,088	(3,447)	26,535	(769.8)	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	1,296,498	873,749	422,749	48.4	5,638,595	3,830,098	1,808,497	47.2
2	LIGHT OIL	773,913	677,013	96,900	14.3	3,927,408	4,081,803	(154,395)	(3.8)
3	COAL	33,453,660	36,336,134	(2,882,474)	(7.9)	152,610,682	166,223,285	(13,612,603)	(8.2)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	35,524,071	37,886,896	(2,362,825)	(6.2)	162,176,685	174,135,186	(11,958,501)	(6.9)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	35,733	19,701	16,032	81.4	153,882	86,386	67,496	78.1
9	LIGHT OIL	20,018	13,953	6,065	43.5	101,834	88,069	13,765	15.6
10	COAL	1,619,937	1,722,342	(102,405)	(5.9)	7,621,449	7,981,447	(359,998)	(4.5)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,675,688	1,755,996	(80,308)	(4.6)	7,877,165	8,155,902	(278,737)	(3.4)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	80,004	46,327	33,677	72.7	339,062	201,342	137,720	68.4
16	LIGHT OIL (BBL)	40,492	25,102	15,390	61.3	192,970	149,585	43,385	29.0
17	COAL (TON)	764,021	786,585	(22,564)	(2.9)	3,630,411	3,592,445	37,966	1.1
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	505,092	292,826	212,266	72.5	2,140,381	1,272,684	867,697	68.2
22	LIGHT OIL	235,837	145,363	90,474	62.2	1,116,292	867,214	249,078	28.7
23	COAL	16,979,336	17,879,746	(900,410)	(5.0)	80,538,614	82,005,491	(1,466,877)	(1.8)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	17,720,265	18,317,935	(597,670)	(3.3)	83,795,287	84,145,389	(350,102)	(0.4)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	2.13	1.12	1.01	-	1.95	1.06	0.89	-
29	LIGHT OIL	1.19	0.79	0.40	-	1.29	1.08	0.21	-
30	COAL	96.68	98.09	(1.41)	-	96.76	97.86	(1.10)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	16.21	18.86	(2.65)	(14.1)	16.63	19.02	(2.39)	(12.6)
36	LIGHT OIL ($/BBL)	19.11	26.97	(7.86)	(29.1)	20.35	27.29	(6.94)	(25.4)
37	COAL ($/TON)	43.79	46.19	(2.40)	(5.2)	42.04	46.27	(4.23)	(9.1)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.57	2.98	(0.41)	(13.8)	2.63	3.01	(0.38)	(12.6)
42	LIGHT OIL	3.28	4.66	(1.38)	(29.6)	3.52	4.71	(1.19)	(25.3)
43	COAL	1.97	2.03	(0.06)	(3.0)	1.89	2.03	(0.14)	(6.9)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	2.00	2.07	(0.07)	(3.4)	1.94	2.07	(0.13)	(6.3)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: AUGUST, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	14,135	14,864	(729)	(4.9)	13,909	14,733	(824)	(5.6)
49	LIGHT OIL	11,781	10,418	1,363	13.1	10,962	9,847	1,115	11.3
50	COAL	10,481	10,381	100	1.0	10,567	10,275	292	2.8
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,575	10,432	143	1.4	10,638	10,317	321	3.1
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.63	4.44	(0.81)	(18.2)	3.66	4.43	(0.77)	(17.4)
56	LIGHT OIL	3.87	4.85	(0.98)	(20.2)	3.86	4.63	(0.77)	(16.6)
57	COAL	2.07	2.11	(0.04)	(1.9)	2.00	2.08	(0.08)	(3.8)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.12	2.16	(0.04)	(1.9)	2.06	2.14	(0.08)	(3.7)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: AUGUST, 1998

SCHEDULE A4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	2127	8.9	90.6	47.9	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	5146	21.6	100.0	60.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	5505	23.1	100.0	59.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	6488	21.3	93.5	53.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	6794	13.6	64.3	62.6	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	26060	17.2	85.5	57.5	16015	HVY.OIL	66017	6321823	417347.8	1018235	3.91	15.42
GAN.#1	114	53946	63.6	84.7	70.1	10995	COAL	27771	21357960	593131.9	1283451	2.38	46.22
GAN.#2	108	38549	48.0	62.1	58.8	12473	COAL	22610	21265701	480817.5	1044933	2.71	46.22
GAN.#3	155	67039	58.1	73.5	64.7	12502	COAL	43527	19255039	838114.1	2011622	3.00	46.22
GAN.#4	169	88323	70.2	86.6	71.1	11968	COAL	53342	19816360	1057044.3	2465228	2.79	46.22
GAN.#5	227	121527	72.0	82.5	76.7	10943	COAL	55869	23802780	1329837.5	2582014	2.12	46.22
GAN.#6	362	183303	68.1	77.8	81.4	10312	COAL	75967	24881500	1890172.9	3510853	1.92	46.22
GANNON STA.	1135	552687	65.5	78.7	73.4	11198	COAL	279086	22176384	6189118.2	12898101	2.33	46.22
B.B.#1	421	234218	74.8	89.3	79.2	10192	COAL	105979	22524180	2387090.1	4364300	1.86	41.18
B.B.#2	416	209082	67.6	80.2	80.2	9981	COAL	91529	22798840	2086755.0	3769237	1.80	41.18
B.B.#3	428	184702	58.0	68.2	77.4	10472	COAL	85771	22550800	1934204.7	3532118	1.91	41.18
B.B. 1 - 3	1265	628002	66.7	79.2	78.9	10204	COAL	283279	22620984	6408049.8	11665655	1.86	41.18
B.B.#4	442	271276	82.5	90.9	82.5	10121	COAL	129586	21188259	2745701.7	5672266	2.09	43.77
B.B. STA.	1707	899278	70.8	82.2	79.8	10179	COAL	412865	22171294	9153751.5	17337921	1.93	41.99
SEB-PHIL. #1(HVY OIL)	17	4908	38.8	97.1	86.2	9071	HVY.OIL	7097	6273256	44521.3	141181	2.88	19.89
SEB-PHIL. #2(HVY OIL)	17	4765	37.7	95.2	84.4	9071	HVY.OIL	6890	6273266	43222.8	137082	2.88	19.90
SEB-PHILLIPS TOTAL	34	9673	38.2	96.2	85.3	9071	HVY.OIL	13987	6273261	87744.1	278263	2.88	19.89
POLK COAL	250	167972	90.3	93.3	96.8	9742	COAL	72070	22706630	1636466.8	3217638	1.92	44.65
POLK OIL	225	7285	4.4	6.7	64.5	7754	LGT.OIL	9735	5802661	56488.9	194876	2.68	20.02
POLK TOTAL	250	175257	94.7	100.0	-	9660	-	-	-	1692955.7	3412514	1.95	-
GAN.C.T.#1	15	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	15	725	6.5	90.6	98.6	17873	LGT.OIL	2232	5805511	12957.9	42020	5.80	18.83
B.B.C.T.#2	65	8039	16.6	100.0	997.4	13025	LGT.OIL	17950	5833092	104704.0	337930	4.20	18.83
B.B.C.T.#3	65	3969	8.2	100.0	98.5	15542	LGT.OIL	10575	5833191	61686.0	199087	5.02	18.83
C.T. TOTAL	160	12733	10.7	89.7	454.5	14085	LGT.OIL	30757	5831125	179347.9	579037	4.55	18.83
TOT. COAL (GN,BB,POLK)	2842	1619937	76.6	81.8	78.8	10481	COAL	764021	22223652	16979336.5	33453660	2.07	43.79
SYSTEM	3490	1675688	64.5	82.5	94.9	10575	-	-	-	17720265.2	35524071	2.12	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)								
1	PURCHASES:								
2	UNITS (BBL)	89,156	46,327	42,829	92.4	331,249	201,342	129,907	64.5
3	UNIT COST ($/BBL)	15.42	17.91	(2.49)	(13.9)	15.31	17.87	(2.56)	(14.3)
4	AMOUNT ($)	1,374,674	829,776	544,898	65.7	5,070,369	3,598,435	1,471,934	40.9
5	BURNED:								
6	UNITS (BBL)	80,004	46,327	33,677	72.7	339,062	201,342	137,720	68.4
7	UNIT COST ($/BBL)	16.21	18.86	(2.65)	(14.1)	16.63	19.02	(2.39)	(12.6)
8	AMOUNT ($)	1,296,498	873,749	422,749	48.4	5,638,595	3,830,098	1,808,497	47.2
9	ENDING INVENTORY:								
10	UNITS (BBL)	182,781	139,530	43,251	31.0	182,781	139,530	43,251	31.0
11	UNIT COST ($/BBL)	15.72	17.81	(2.09)	(11.7)	15.72	17.81	(2.09)	(11.7)
12	AMOUNT ($)	2,873,809	2,485,036	388,773	15.6	2,873,809	2,485,036	388,773	15.6
13									
14	DAYS SUPPLY:	361	413	(52)	(12.6)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	45,894	36,853	9,041	24.5	231,527	205,724	25,803	12.5
17	UNIT COST ($/BBL)	18.27	27.07	(8.80)	(32.5)	18.97	27.11	(8.14)	(30.0)
18	AMOUNT ($)	838,595	997,753	(159,158)	(16.0)	4,391,171	5,576,568	(1,185,397)	(21.3)
19	BURNED:								
20	UNITS (BBL)	40,492	25,102	15,390	61.3	192,970	149,585	43,385	29.0
21	UNIT COST ($/BBL)	19.11	26.97	(7.86)	(29.1)	20.35	27.29	(6.94)	(25.4)
22	AMOUNT ($)	773,913	677,013	96,900	14.3	3,927,408	4,081,803	(154,395)	(3.8)
23	ENDING INVENTORY:								
24	UNITS (BBL)	66,611	60,844	5,767	9.5	66,611	60,844	5,767	9.5
25	UNIT COST ($/BBL)	19.45	27.13	(7.68)	(28.3)	19.45	27.13	(7.68)	(28.3)
26	AMOUNT ($)	1,295,527	1,650,570	(355,043)	(21.5)	1,295,527	1,650,570	(355,043)	(21.5)
27									
28	DAYS SUPPLY: NORMAL	76	73	3	4.1	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	10	9	1	11.1	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	725,431	737,737	(12,306)	(1.7)	3,565,805	3,712,237	(146,432)	(3.9)
32	UNIT COST ($/TON)	45.03	45.65	(0.62)	(1.4)	41.74	45.73	(3.99)	(8.7)
33	AMOUNT ($)	32,667,406	33,680,043	(1,012,637)	(3.0)	148,818,936	169,747,000	(20,928,064)	(12.3)
34	BURNED:								
35	UNITS (TONS)	764,021	786,585	(22,564)	(2.9)	3,630,411	3,592,445	37,966	1.1
36	UNIT COST ($/TON)	43.79	46.19	(2.40)	(5.2)	42.04	46.27	(4.23)	(9.1)
37	AMOUNT ($)	33,453,660	36,336,134	(2,882,474)	(7.9)	152,610,682	166,223,285	(13,612,603)	(8.2)
38	ENDING INVENTORY:								
39	UNITS (TONS)	567,723	648,141	(80,418)	(12.4)	567,723	648,141	(80,418)	(12.4)
40	UNIT COST ($/TON)	42.83	45.74	(2.91)	(6.4)	42.83	45.74	(2.91)	(6.4)
41	AMOUNT ($)	24,316,444	29,647,502	(5,331,058)	(18.0)	24,316,444	29,647,502	(5,331,058)	(18.0)
42									
43	DAYS SUPPLY:	25	29	(4)	(13.8)	-	-	-	-
	NATURAL GAS								
44	*PURCHASES:*								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST, 1998

	OTHER		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	11,386
FUEL ANALYSIS	140
LUBE OIL	0
TOTAL	11,526

(2)RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(13,433)	(252,337)
OTHER USAGE	(954)	(18,282)
TOTAL	(14,387)	(270,619)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
PROPANE IGNITION	20
IGNITION	240,951
FUEL ANALYSIS	30,911
AERIAL SURVEY ADJ.	15,217
ADDITIVES	101,200
TOTAL	388,299

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF AUGUST, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	74,344.0	0.0	74,344.0	1.618	2.185	1,202,600.00	1,624,700.00	337,680.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,840.0	0.0	5,840.0	1.836	1.836	107,200.00	107,200.00	
VARIOUS	SEPARATED	SCH. -D	35,228.0	0.0	35,228.0	1.477	1.720	520,300.00	605,800.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	21,235.0	0.0	21,235.0	2.389	3.197	507,200.00	678,800.00	
LAKELAND/FMPA		SCH. -D	63,240.0	0.0	63,240.0	1.503	1.563	950,500.00	988,400.00	
VARIOUS	JURISDICTIONAL	SCH. -J	5,952.0	0.0	5,952.0	2.354	2.354	140,100.00	140,100.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	205,839.0	0.0	205,839.0	1.665	2.014	3,427,900.00	4,145,000.00	337,680.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(94,400.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						337,680.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	205,839.0	0.0	205,839.0	1.784	2.014	3,671,180.00	4,145,000.00	337,680.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	10,139.0	0.0	10,139.0	1.995	2.765	202,306.20	280,378.35	62,457.72
FLA. PWR. & LIGHT		ECON.-C	1,431.0	0.0	1,431.0	2.261	2.910	32,348.83	41,642.17	7,434.68
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	185.0	0.0	185.0	2.021	2.852	3,739.15	5,276.43	1,229.82
CITY OF HOMESTEAD		ECON.-C	342.0	0.0	342.0	1.782	2.162	6,093.43	7,393.48	1,040.04
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	922.0	0.0	922.0	1.868	3.344	17,226.79	30,829.31	10,882.02
CITY OF NEW SMYRNA BCH.		ECON.-C	19.0	0.0	19.0	1.994	4.345	378.77	825.55	357.42
ORLANDO UTIL. COMM.		ECON.-C	2,680.0	0.0	2,680.0	1.704	1.769	45,667.07	47,422.50	1,404.34
SEMINOLE ELECTRIC CO-OP		ECON.-C	2,643.0	0.0	2,643.0	1.782	2.128	47,085.85	56,242.45	7,325.28
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	75.0	0.0	75.0	1.850	2.237	1,387.78	1,677.73	231.96
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	12,372.0	0.0	12,372.0	1.695	1.983	209,762.99	245,278.35	28,412.29
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	323.0	0.0	323.0	4.309	5.200	13,918.07	16,796.00	2,302.34
NP ENERGY INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	885.0	0.0	885.0	3.125	8.032	27,656.25	71,083.20	34,741.56
TENNESSEE VALLEY AUTHORITY		ECON.-C	1,936.0	0.0	1,936.0	2.554	5.233	49,436.16	101,302.85	41,493.35
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	12,294.0	0.0	12,294.0	1.664	1.810	204,560.80	222,551.14	
REEDY CREEK	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.518	1.822	225,878.40	271,113.60	
WAUCHULA	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.518	1.822	56,469.60	67,778.40	
FT. MEADE	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.518	1.822	56,469.60	67,778.40	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	CONTRACT	SCH. -D	55,054.0	0.0	55,054.0	2.003	2.639	1,102,731.62	1,452,875.06	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	4,722.0	573.9	4,148.1	2.624	2.624	108,865.93	108,865.93	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	961.0	0.0	961.0	1.756	1.756	16,873.73	16,873.73	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	1,316.0	0.0	1,316.0	4.990	4.990	65,663.98	65,663.98	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	8,215.0	0.0	8,215.0	2.243	2.243	184,242.70	184,242.70	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	4,220.0	0.0	4,220.0	2.340	2.340	98,735.34	98,735.34	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF GAINESVILLE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF AUGUST, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FMPA	SCH. -D	63,240.0	63,240.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	2,512.0	0.0	2,512.0	2.293	2.822	57,599.92	70,892.68	10,634.21 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	1,352.0	0.0	1,352.0	4.731	5.264	63,969.66	71,162.53	5,754.30 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	105.0	0.0	105.0	1.769	2.099	1,857.38	2,204.42	277.63 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	24.0	0.0	24.0	1.762	2.233	422.92	536.01	90.47 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	2.0	0.0	2.0	1.748	1.928	34.96	38.56	2.88 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO HOMESTEAD	ECON.-C	25.0	0.0	25.0	1.748	2.067	436.96	516.83	63.90 *
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	218.0	0.0	218.0	1.753	2.131	3,821.40	4,645.43	659.22 *
HARDEE PWR. PARTNERS TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	239.0	0.0	239.0	2.410	3.217	5,760.16	7,689.15	1,543.19 *
HARDEE PWR. PARTNERS TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	910.0	0.0	910.0	4.959	5.939	45,126.90	54,044.71	7,134.25 *
HARDEE PWR. PARTNERS TO TVA	ECON.-C	387.0	0.0	387.0	3.115	4.279	12,055.05	16,559.04	3,603.19 *
FLA. PWR. CORP.	C.T. -A	80.0	0.0	80.0	5.395	5.395	4,315.85	4,315.85	
ADJUSTMENTS TO JULY 1998:									
HARDEE POWER PARTNERS CONTRACT	SCH. -D	(62,938.0)	0.0	(62,938.0)	2.005	2.644	(1,261,906.90)	(1,664,080.72)	
HARDEE POWER PARTNERS CONTRACT	SCH. -D	62,938.0	0.0	62,938.0	2.003	2.639	1,260,648.14	1,660,933.82	
CITY OF NEW SMYRNA BCH. JURISD.	SCH. -J	(4,640.0)	0.0	(4,640.0)	2.468	2.468	(114,533.00)	(114,533.00)	
CITY OF NEW SMYRNA BCH. JURISD.	SCH. -J	4,640.0	0.0	4,640.0	2.340	2.340	108,562.08	108,562.08	
REEDY CREEK JURISD.	SCH. -J	(9,329.0)	0.0	(9,329.0)	2.224	2.224	(207,441.13)	(207,441.13)	
REEDY CREEK JURISD.	SCH. -J	9,329.0	0.0	9,329.0	2.224	2.224	207,442.63	207,442.63	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	(13,377.0)	0.0	(13,377.0)	1.685	1.831	(225,395.30)	(244,973.70)	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	13,377.0	0.0	13,377.0	1.685	1.801	225,395.30	240,922.70	
SUB-TOTAL ECONOMY POWER SALES		39,726.0	0.0	39,726.0	2.135	2.856	848,092.65	1,134,437.73	229,076.06
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		34,614.0	0.0	34,614.0	1.570	1.806	543,378.40	625,170.54	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		5,683.0	573.9	5,109.1	2.461	2.461	125,739.66	125,739.66	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		13,751.0	0.0	13,751.0	2.492	2.492	342,672.60	342,672.60	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		55,054.0	0.0	55,054.0	2.001	2.633	1,101,472.86	1,449,728.16	
SUB-TOTAL OTHER POWER SALES		63,320.0	63,240.0	80.0	5.395	5.395	4,315.85	4,315.85	
TOTAL INCLUDING VARIABLE O & M COSTS -		212,148.0	63,813.9	148,334.1	1.999	2.482	2,965,672.02	3,682,064.54	229,076.06
LESS VARIABLE O & M COSTS -							(56,699.84)		
LESS VARIABLE O & M COSTS - HARDEE -							(808.36)		
LESS TRANSMISSION COSTS SCH.-D (SEP.)							(19,146.90)		
PLUS 80% OF ECON. ENERGY SALES PROFITS -							229,076.06		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS -		212,148.0	63,813.9	148,334.1	2.102	2.482	3,118,092.98	3,682,064.54	229,076.06
CURRENT MONTH:									
DIFFERENCE -		6,309.0	63,813.9	(57,504.9)	0.318	0.468	(553,087.02)	(462,935.46)	(108,603.94)
DIFFERENCE % -		3.1	0.0	(27.9)	17.8	23.2	(15.1)	(11.2)	(32.2)
PERIOD TO DATE:									
ACTUAL -		1,070,131.0	297,455.5	772,675.5	2.418	2.882	18,684,234.64	22,268,436.52	4,819,429.90
ESTIMATED -		1,036,582.0	0.0	1,036,582.0	1.790	2.027	18,558,400.00	21,013,800.00	1,921,600.00
DIFFERENCE -		33,549.0	297,455.5	(263,906.5)	0.628	0.855	125,834.64	1,254,636.52	2,897,829.90
DIFFERENCE % -		3.2	0.0	(25.5)	35.1	42.2	0.7	6.0	150.8

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $33,882.54 HAS BEEN EXCLUDED.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF AUGUST, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	7,483.0	0.0	4,591.0	2,892.0	5.163	5.163	149,300.00
HARDEE POWER PARTNERS	IPP	67,227.0	0.0	0.0	67,227.0	3.046	3.046	2,047,700.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	74,710.0	0.0	4,591.0	70,119.0	3.133	3.133	2,197,000.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	98,870.0	0.0	0.0	98,870.0	2.523	2.523	2,494,333.56
HARDEE PWR. PART.-OTHERS	IPP	5,774.0	0.0	0.0	5,774.0	3.246	3.260	187,441.82
FLA. POWER CORP.	SCH.-Ja	3,948.0	0.0	2,796.7	1,151.3	5.200	5.200	59,862.77
FLA. POWER CORP.	SCH.-Jc	10,159.0	0.0	0.0	10,159.0	2.710	2.710	275,306.95
FLA. POWER & LIGHT	SCH.-Ja	8,341.0	0.0	6,855.9	1,485.1	5.623	5.623	83,510.48
FLA. POWER & LIGHT	SCH.-Jc	7,318.0	0.0	0.0	7,318.0	3.229	3.229	236,300.25
CITY OF LAKELAND	SCH.-Ja	2,683.0	0.0	1,304.7	1,378.3	4.636	4.636	63,902.42
CITY OF LAKELAND	SCH.-Jc	2,720.0	0.0	0.0	2,720.0	3.200	3.200	87,029.15
ORLANDO UTIL. COMM.	SCH.-Ja	9,041.0	0.0	5,556.3	3,484.7	5.168	5.168	180,104.76
ORLANDO UTIL. COMM.	SCH.-Jc	4,927.0	0.0	0.0	4,927.0	3.808	3.808	187,614.66
SEMINOLE ELEC. CO-OP	SCH.-Ja	467.0	0.0	353.0	114.0	5.500	5.500	6,270.31
SEMINOLE ELEC. CO-OP	SCH.-Jc	90.0	0.0	0.0	90.0	4.000	4.000	3,600.00
THE ENERGY AUTH.	SCH.-Ja	798.0	0.0	333.2	464.8	4.922	4.922	22,876.55
THE ENERGY AUTH.	SCH.-Jc	239.0	0.0	0.0	239.0	4.417	4.417	10,557.42
REEDY CREEK	SCH.-Ja	60.0	0.0	60.0	0.0	0.000	0.000	0.00
OGLETHORPE	SCH.-Jc	1,517.0	0.0	0.0	1,517.0	5.584	5.584	84,715.76
LAKE WORTH UTILITIES	SCH.-Ja	275.0	0.0	275.0	0.0	0.000	0.000	0.00
KISSIMMEE ELEC. UTIL.	SCH.-Ja	35.0	0.0	35.0	0.0	0.000	0.000	0.00
KISSIMMEE ELEC. UTIL.	SCH.-Jc	15.0	0.0	0.0	15.0	11.000	11.000	1,650.00
PECO	OTHER	39,215.0	39,215.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO JULY 1998:								
HARDEE PWR. PART.-NATIVE	IPP	(109,567.0)	0.0	0.0	(109,567.0)	2.637	2.637	(2,889,271.22)
HARDEE PWR. PART.-NATIVE	IPP	109,567.0	0.0	0.0	109,567.0	2.586	2.586	2,833,932.67
TOTAL		220,517.0	63,240.0	17,569.8	139,707.2	2.813	2.813	3,929,738.31
CURRENT MONTH:								
DIFFERENCE	-	145,807.0	63,240.0	12,978.8	69,588.2	(0.320)	(0.320)	1,732,738.31
DIFFERENCE %	-	195.2	0.0	282.7	99.2	(10.2)	(10.2)	78.9
PERIOD TO DATE:								
ACTUAL	-	878,142.0	295,371.0	70,628.7	512,142.3	3.159	3.168	16,179,367.36
ESTIMATED	-	304,727.0	0.0	16,896.0	287,831.0	3.122	3.122	8,987,100.00
DIFFERENCE	-	573,415.0	295,371.0	53,732.7	224,311.3	0.037	0.046	7,192,267.36
DIFFERENCE %	-	188.2	0.0	318.0	77.9	1.2	1.5	80.0

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF AUGUST, 1998

SCHEDULE A8

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	41,305.0	0.0	0.0	41,305.0	2.373	2.373	980,200.00
TOTAL	-	41,305.0	0.0	0.0	41,305.0	2.373	2.373	980,200.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	974.0	0.0	0.0	974.0	2.947	2.947	28,699.69
McKAY BAY REFUSE	COGEN.	10,929.0	0.0	0.0	10,929.0	1.884	1.884	205,857.86
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	84.0	0.0	0.0	84.0	4.758	4.758	3,996.41
HILLSBOROUGH COUNTY	COGEN.	20,140.0	0.0	0.0	20,140.0	1.885	1.885	379,663.06
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	682.0	0.0	0.0	682.0	3.109	3.109	21,205.17
FARMLAND HYDRO LP	COGEN.	256.0	0.0	0.0	256.0	2.663	2.663	6,816.96
IMC-AGRICO-S. PIERCE	COGEN.	385.0	0.0	0.0	385.0	3.674	3.674	14,146.10
AUBURNDALE POWER PARTNERS	COGEN.	1,228.0	0.0	0.0	1,228.0	1.791	1.791	21,987.78
ORANGE COGENERATION L.P.	COGEN.	7,268.0	0.0	0.0	7,268.0	1.874	1.874	136,228.23
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	594.0	(594.0)	5.098	5.098	(30,284.94)
SUB-TOTAL FOR AUG., 1998	-	41,946.0	0.0	594.0	41,352.0	1.906	1.906	788,316.32
ADJUSTMENTS FOR JUNE, 1998								
IMC-AGRICO-NICHOLS	COGEN.	(1,657.0)	0.0	0.0	(1,657.0)	3.776	3.776	(62,568.03)
		1,657.0	0.0	0.0	1,657.0	3.840	3.840	63,627.67
McKAY BAY REFUSE	COGEN.	(9,339.0)	0.0	0.0	(9,339.0)	1.722	1.722	(160,786.81)
		9,339.0	0.0	0.0	9,339.0	1.757	1.757	164,077.88
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.	(38.0)	0.0	0.0	(38.0)	13.613	13.613	(5,173.08)
		38.0	0.0	0.0	38.0	13.652	13.652	5,187.68
HILLSBOROUGH COUNTY	COGEN.	(19,053.0)	0.0	0.0	(19,053.0)	1.725	1.725	(328,721.87)
		19,053.0	0.0	0.0	19,053.0	1.760	1.760	335,337.66
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.	(328.0)	0.0	0.0	(328.0)	10.877	10.877	(35,677.67)
		328.0	0.0	0.0	328.0	10.882	10.882	35,693.08
FARMLAND HYDRO LP	COGEN.	(56.0)	0.0	0.0	(56.0)	15.299	15.299	(8,567.37)
		56.0	0.0	0.0	56.0	15.292	15.292	8,563.41
IMC-AGRICO-S. PIERCE	COGEN.	(632.0)	0.0	0.0	(632.0)	8.937	8.937	(56,480.14)
		632.0	0.0	0.0	632.0	8.980	8.980	56,752.49
AUBURNDALE POWER PARTNERS	COGEN.	(71.0)	0.0	0.0	(71.0)	10.042	10.042	(7,130.04)
		71.0	0.0	0.0	71.0	10.840	10.840	7,696.06
ORANGE COGENERATION L.P.	COGEN.	(7,567.0)	0.0	0.0	(7,567.0)	1.814	1.814	(137,269.32)
		7,567.0	0.0	0.0	7,567.0	1.810	1.810	136,969.60
AS AVAILABLE ASSIGNMENT	COGEN.	729.0	0.0	0.0	729.0	16.001	16.001	116,644.78
		(729.0)	0.0	0.0	(729.0)	15.983	15.983	(116,514.10)
SUB-TOTAL FOR JUNE, 1998 ADJ.		0.0	0.0	0.0	0.0	0.000	0.000	11,661.88
GRAND TOTAL		41,946.0	0.0	594.0	41,352.0	1.935	1.935	799,978.20
CURRENT MONTH:								
DIFFERENCE	-	641.0	0.0	594.0	47.0	(0.438)	(0.438)	(180,221.80)
DIFFERENCE %	-	1.6	0.0	0.0	0.1	(18.5)	(18.5)	(18.4)
PERIOD TO DATE:								
ACTUAL		199,643.0	0.0	2,749.7	196,893.3	1.800	1.800	3,544,294.82
ESTIMATED		197,776.0	0.0	0.0	197,776.0	2.330	2.330	4,608,600.00
DIFFERENCE	-	1,867.0	0.0	2,749.7	(882.7)	(0.530)	(0.530)	(1,064,305.18)
DIFFERENCE %	-	0.9	0.0	0.0	(0.4)	(22.7)	(22.7)	(23.1)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF AUGUST, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	6,371.0	4.382	279,200.00	5.027	320,300.00	41,100.00
TOTAL	-	6,371.0	4.382	279,200.00	5.027	320,300.00	41,100.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	120.0	2.366	2,839.25	2.969	3,562.90	723.65
FLA. PWR. & LIGHT	ECON.-C	842.0	2.765	23,283.04	2.771	23,331.06	48.02
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	84.0	3.659	3,073.82	4.251	3,570.42	496.60
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	5.0	3.828	191.38	4.043	202.15	10.77
ORLANDO UTIL. COMM.	ECON.-C	346.0	3.198	11,065.59	3.930	13,597.10	2,531.51
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	635.0	3.092	19,635.87	4.098	26,024.23	6,388.36
ADJUSTMENTS TO JULY 1998							
FLA. PWR. & LIGHT	ECON.-C	(549.0)	3.119	(17,124.66)	3.129	(17,177.58)	(52.92)
FLA. PWR. & LIGHT	ECON.-C	549.0	3.121	17,131.91	3.129	17,177.58	45.67
FLA. PWR. & LIGHT	ECON.-C *			(11,415.85)			
TOTAL	-	2,032.0	2.396	48,680.35	3.459	70,287.86	10,191.66
CURRENT MONTH:							
DIFFERENCE	-	(4,339.0)	(1.986)	(230,519.65)	(1.568)	(250,012.14)	(30,908.34)
DIFFERENCE %	-	(68.1)	(45.3)	(82.6)	(31.2)	(78.1)	(75.2)
PERIOD TO DATE:							
ACTUAL		5,723.0	2.841	162,614.20	3.492	199,875.33	37,261.13
ESTIMATED		26,193.0	4.311	1,129,100.00	5.078	1,330,200.00	201,100.00
DIFFERENCE	-	(20,470.0)	(1.470)	(966,485.80)	(1.586)	(1,130,324.67)	(163,838.87)
DIFFERENCE %	-	(78.2)	(34.1)	(85.6)	(31.2)	(85.0)	(81.5)

* 1997 REFUND ON TC CHARGES.

COMMISSION SCHEDULES A1 - A9

JULY 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	35,135,362	37,149,056	(2,013,694)	(5.4)	1,677,832	1,742,018	(64,186)	(3.7)	2.09409	2.13253	(0.03844)	(1.8)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,270)	(3,500)	(770)	22.0	1,677,832 (a)	1,742,018 (a)	(64,186)	(3.7)	(0.00025)	(0.00020)	(0.00005)	25.0
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,677,832 (a)	1,742,018 (a)	(64,186)	(3.7)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,677,832 (a)	1,742,018 (a)	(64,186)	(3.7)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	35,131,092	37,145,556	(2,014,464)	(5.4)	1,677,832	1,742,018	(64,186)	(3.7)	2.09384	2.13233	(0.03849)	(1.8)
6. Fuel Cost of Purchased Power - Firm (A7)	4,385,100	2,229,300	2,155,800	96.7	141,227	71,667	69,560	97.1	3.10500	3.11064	(0.00564)	(0.2)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	45,128	359,500	(314,372)	(87.4)	1,440	8,039	(6,599)	(82.1)	3.13389	4.47195	(1.33806)	(29.9)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	701,719	977,100	(275,381)	(28.2)	37,438	41,305	(3,867)	(9.4)	1.87435	2.36557	(0.49122)	(20.8)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	5,131,947	3,565,900	1,566,047	43.9	180,105	121,011	59,094	48.8	2.84942	2.94676	(0.09734)	(3.3)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,857,937	1,863,029	(5,092)	(0.3)				
14. Fuel Cost of Economy Sales (A6)	1,010,323	1,048,400	(38,077)	(3.6)	49,079	73,058	(23,979)	(32.8)	2.05856	1.43502	0.62354	43.5
15. Gain on Economy Sales - 80% (A6)	988,325	335,680	652,645	194.4	49,079 (a)	73,058 (a)	(23,979)	(32.8)	2.01374	0.45947	1.55427	338.3
16. Fuel Cost of Sch. D Separ. Sales (A6)	538,330	520,500	17,830	3.4	35,697	35,228	469	1.3	1.50805	1.47752	0.03053	2.1
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	105,456	103,600	1,856	1.8	4,713	5,756	(1,043)	(18.1)	2.23756	1.79986	0.43770	24.3
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	321,974	140,100	181,874	129.8	13,969	5,952	8,017	134.7	2.30492	2.35383	(0.04891)	(2.1)
20. Fuel Cost of RPP Sch. D Separ. Sales (A6)	1,258,313	580,500	677,813	116.8	62,938	24,431	38,507	157.6	1.99929	2.37608	(0.37679)	(15.9)
21. Fuel Cost of Other Power Sales (A6)	0	951,000	(951,000)	(100.0)	0	63,240	(63,240)	(100.0)	0.00000	1.50380	(1.50380)	(100.0)
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	4,222,721	3,679,780	542,941	14.8	166,396	207,665	(41,269)	(19.9)	2.53775	1.77198	0.76577	43.2
23. Net Inadvertant Interchange					(721)	0	(721)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					(879)	0	(879)	0.0				
25. Interchange and Wheeling Losses					1,029	3,200	(2,171)	(67.8)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	36,040,318	37,031,676	(991,358)	(2.7)	1,688,912	1,652,164	36,748	2.2	2.13394	2.24140	(0.10746)	(4.8)
27. Net Unbilled	(366,333) (a)	671,994 (a)	(1,038,327)	(154.5)	(17,167)	29,981	(47,148)	(157.3)	(0.02169)	0.04067	(0.06236)	(153.3)
28. Company Use	98,353 (a)	85,173 (a)	13,180	15.5	4,609	3,800	809	21.3	0.00604	0.00553	0.00051	9.2
29. T & D Losses	1,535,925 (a)	1,780,680 (a)	(244,755)	(13.7)	71,976	79,445	(7,469)	(9.4)	0.09426	0.11571	(0.02145)	(18.5)
30. System KWH Sales	36,040,318	37,031,676	(991,358)	(2.7)	1,629,494	1,538,938	90,556	5.9	2.21175	2.40631	(0.19456)	(8.1)
31. Wholesale KWH Sales	(648,419)	(567,025)	(81,394)	14.4	(29,317)	(23,564)	(5,753)	24.4	2.21175	2.40632	(0.19457)	(8.1)
32. Jurisdictional KWH Sales	35,391,899	36,464,651	(1,072,752)	(2.9)	1,600,177	1,515,374	84,803	5.6	2.21175	2.40631	(0.19456)	(8.1)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	35,396,500	36,469,391	(1,072,891)	(2.9)	1,600,177	1,515,374	84,803	5.6	2.21204	2.40663	(0.19459)	(8.1)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	413,939	415,069	(1,130)	(0.3)	1,600,177	1,515,374	84,803	5.6	0.02587	0.02739	(0.00152)	(5.5)
36. Fuel Credit Differential - FMPA Sale	0	(527,637)	527,637	(100.0)	1,600,177	1,515,374	84,803	5.6	0.00000	(0.03482)	0.03482	(100.0)
37. True-up *	(728,854)	(728,854)	0	0.0	1,600,177	1,515,374	84,803	5.6	(0.04555)	(0.04810)	0.00255	(5.3)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	35,081,585	35,627,969	(546,384)	(1.5)	1,600,177	1,515,374	84,803	5.6	2.19236	2.35110	(0.15874)	(6.8)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.19418	2.35305	(0.15887)	(6.8)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,600,177	1,515,374	84,803	5.6	(0.00379)	(0.00400)	0.00021	(5.2)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	35,020,994	35,567,378	(546,384)	(1.5)	1,600,177	1,515,374	84,803	5.6	2.19039	2.34905	(0.15866)	(6.8)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.190	2.349	(0.159)	(6.8)

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JULY, 1998

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	126,652,614	136,248,290	(9,595,676)	(7.0)	6,201,477	6,399,906	(198,429)	(3.1)	2.04230	2.12891	(0.08661)	(4.1)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(16,342)	(14,000)	(2,342)	16.7	6,201,477 (a)	6,399,906 (a)	(198,429)	(3.1)	(0.00026)	(0.00022)	(0.00004)	18.2
4b. Adjustments to Fuel Cost	0	0	0	0.0	6,201,477 (a)	6,399,906 (a)	(198,429)	(3.1)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	6,201,477 (a)	6,399,906 (a)	(198,429)	(3.1)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	126,636,272	136,234,290	(9,598,018)	(7.0)	6,201,477	6,399,906	(198,429)	(3.1)	2.04203	2.12869	(0.08666)	(4.1)
6. Fuel Cost of Purchased Power - Firm (A7)	12,249,629	6,790,100	5,459,529	80.4	372,435	217,712	154,723	71.1	3.28906	3.11885	0.17021	5.5
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	113,933	849,900	(735,967)	(86.6)	3,691	19,822	(16,131)	(81.4)	3.08678	4.28766	(1.20088)	(28.0)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	2,744,317	3,628,400	(884,083)	(24.4)	155,541	156,471	(930)	(0.6)	1.76437	2.31890	(0.55453)	(23.9)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	15,107,879	11,268,400	3,839,479	34.1	531,667	394,005	137,662	34.9	2.84161	2.85996	(0.01835)	(0.6)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					6,733,144	6,793,911	(60,767)	(0.9)				
14. Fuel Cost of Economy Sales (A6)	4,213,746	5,141,000	(927,254)	(18.0)	250,775	337,001	(86,226)	(25.6)	1.68029	1.52551	0.15478	10.1
15. Gain on Economy Sales - 80% (A6)	4,590,354	1,583,920	3,006,434	189.8	250,775	337,001 (a)	(86,226)	(25.6)	1.83047	0.47000	1.36047	289.5
16. Fuel Cost of Sch. D Separ. Sales (A6)	1,888,670	1,894,700	(6,030)	(0.3)	129,772	129,559	213	0.2	1.45538	1.46242	(0.00704)	(0.5)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	324,890	328,800	(3,910)	(1.2)	19,285	19,113	172	0.9	1.68468	1.72030	(0.03562)	(2.1)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,909	0	2,909	0.0	75	0	75	0.0	3.87867	0.00000	3.87867	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	922,793	405,300	517,493	127.7	39,606	17,112	22,494	131.5	2.32993	2.36851	(0.03858)	(1.6)
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	3,358,623	1,843,800	1,514,823	82.2	168,165	79,078	89,087	112.7	1.99722	2.33162	(0.33440)	(14.3)
21. Fuel Cost of Other Power Sales (A6)	264,157	3,689,700	(3,425,543)	(92.8)	16,664	248,880	(232,216)	(93.3)	1.58520	1.48252	0.10268	6.9
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	15,566,142	14,887,220	678,922	4.6	624,342	830,743	(206,401)	(24.8)	2.49321	1.79204	0.70117	39.1
23. Net Inadvertant Interchange					(448)	0	(448)	0.0				
24. Wheeling Rec'd. less Wheeling Del'v'd.					414	0	414	0.0				
25. Interchange and Wheeling Losses					10,213	12,700	(2,487)	(19.6)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	126,178,009	132,615,470	(6,437,461)	(4.9)	6,098,555	5,950,468	148,087	2.5	2.06898	2.22866	(0.15968)	(7.2)
27. Net Unbilled	4,767,344 (a)	3,844,795 (a)	922,549	24.0	230,420	172,516	57,904	33.6	0.07817	0.06461	0.01356	21.0
28. Company Use	343,554 (a)	338,756 (a)	4,798	1.4	16,605	15,200	1,405	9.2	0.00616	0.00619	(0.00003)	(0.5)
29. T & D Losses	5,637,081 (a)	6,453,776 (a)	(816,695)	(12.7)	272,457	289,581	(17,124)	(5.9)	0.10104	0.11792	(0.01688)	(14.3)
30. System KWH Sales	126,178,009	132,615,470	(6,437,461)	(4.9)	5,579,073	5,473,171	105,902	1.9	2.26163	2.42301	(0.16138)	(6.7)
31. Wholesale KWH Sales	(2,033,134)	(1,379,517)	(653,617)	47.4	(90,163)	(56,856)	(33,307)	58.6	2.25495	2.42633	(0.17138)	(7.1)
32. Jurisdictional KWH Sales	124,144,875	131,235,953	(7,091,078)	(5.4)	5,488,910	5,416,315	72,595	1.3	2.26174	2.42297	(0.16123)	(6.7)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	124,161,014	131,253,014	(7,092,000)	(5.4)	5,488,910	5,416,315	72,595	1.3	2.26203	2.42329	(0.16126)	(6.7)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	1,671,695	(1,684,470)	3,356,165	(199.2)	5,488,910	5,416,315	72,595	1.3	0.03046	(0.03110)	0.06156	(197.9)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(2,030,617)	2,017,438	(99.4)	5,488,910	5,416,315	72,595	1.3	(0.00024)	(0.03749)	0.03725	(99.4)
37. True-up *	(2,915,416)	(2,915,416)	0	0.0	5,488,910	5,416,315	72,595	1.3	(0.05311)	(0.05383)	0.00072	(1.3)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	122,904,114	124,622,511	(1,718,397)	(1.4)	5,488,910	5,416,315	72,595	1.3	2.23914	2.30087	(0.06173)	(2.7)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.24100	2.30278	(0.06178)	(2.7)
41. GPIF * (Already Adjusted for Taxes)	(242,364)	(242,364)	0	0.0	5,488,910	5,416,315	72,595	1.3	(0.00442)	(0.00447)	0.00005	(1.1)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	122,661,750	124,380,147	(1,718,397)	(1.4)	5,488,910	5,416,315	72,595	1.3	2.23658	2.29831	(0.06173)	(2.7)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.237	2.298	(0.061)	(2.7)

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,135,362	37,149,056	(2,013,694)	(5.4)	126,652,614	136,248,290	(9,595,676)	(7.0)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	4,222,721	3,679,780	542,941	14.8	15,566,142	14,887,220	678,922	4.6
3. FUEL COST OF PURCHASED POWER	4,385,100	2,229,300	2,155,800	96.7	12,249,629	6,790,100	5,459,529	80.4
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	701,719	977,100	(275,381)	(28.2)	2,744,317	3,628,400	(884,083)	(24.4)
4. ENERGY COST OF ECONOMY PURCHASES	45,128	359,500	(314,372)	(87.4)	113,933	849,900	(735,967)	(86.6)
5. TOTAL FUEL & NET POWER TRANSACTION	36,044,588	37,035,176	(990,588)	(2.7)	126,194,351	132,629,470	(6,435,119)	(4.9)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,270)	(3,500)	(770)	22.0	(16,342)	(14,000)	(2,342)	0.0
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	36,040,318	37,031,676	(991,358)	(2.7)	126,178,009	132,615,470	(6,437,461)	(4.9)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,600,177	1,515,374	84,803	5.6	5,488,910	5,416,315	72,595	1.3
2. NONJURISDICTIONAL SALES	29,317	23,564	5,753	24.4	90,163	56,856	33,307	58.6
3. TOTAL SALES	1,629,494	1,538,938	90,556	5.9	5,579,073	5,473,171	105,902	1.9
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9820085	0.9846881	(0.0026796)	(0.3)	0.9838391	0.9896119	(0.0057728)	(0.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

C. TRUE-UP CALCULATION	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
1. JURISDICTIONAL FUEL REVENUE	37,061,848	35,429,593	1,632,255	4.6	126,970,275	126,552,961	417,314	0.3
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,854	728,854	0	0.0	2,915,416	2,915,416	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	242,364	242,364	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	37,851,293	36,219,038	1,632,255	4.5	130,128,055	129,710,741	417,314	0.3
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	36,040,318	37,031,676	(991,358)	(2.7)	126,178,009	132,615,470	(6,437,461)	(4.9)
5. JURISDIC. SALES- % TOTAL KWH SALES (LINE B-4)	0.9820085	0.9846881	(0.0026796)	(0.3)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	35,391,899	36,464,651	(1,072,752)	(2.9)	124,144,875	131,235,953	(7,091,078)	(5.4)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	35,396,500	36,469,391	(1,072,891)	(2.9)	124,161,014	131,253,014	(7,092,000)	(5.4)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	421,523	421,523	0	0.0	1,698,278	1,701,278	(3,000)	(0.2)
6D.(LINE 6C x LINE 5)	413,939	415,069	(1,130)	(0.3)	1,671,695	1,684,470	(12,775)	(0.8)
6E. INTEREST ON SEPT. 97 ADJ. ON FUEL CREDIT DIFFERENTIAL-FMPA/LKL SALE	0	0	0	0.0	0	0	0	0.0
6F. FUEL CREDIT DIFFERENTIAL-FMPA SALE	0	(527,637)	527,637	0.0	(13,179)	(2,030,617)	2,017,438	(99.4)
6G. REVENUE REFUND TRUE-UP ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
6H. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6I. TRANSMISSION ADJ. (JAN.-NOV. 97)	0	0	0	0.0	0	0	0	0.0
6J. JURISDIC. TOTAL FUEL & NET PWR. INCL. ALL ADJUSTMENTS	35,810,439	36,356,823	(546,384)	(1.5)	125,819,530	130,906,867	(5,087,337)	(3.9)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6J)	2,040,854	(137,785)	2,178,639	(1,581.2)	4,308,525	(1,196,126)	5,504,651	(460.2)
8. INTEREST PROVISION FOR THE MONTH	24,278	3,692	20,586	557.6	81,653	47,276	34,377	72.7
9. TRUE-UP & INT. PROV. BEG. OF MONTH	10,607,426	7,214,209	3,393,217	47.0	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,854)	(728,854)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	5,901,297	308,855	5,592,442	1,810.7	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

	CURRENT MONTH				PERIOD TO DATE			
D. INTEREST PROVISION	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	4,565,019	1,171,802	3,393,217	289.6	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 +C-9a + C-10)	5,877,019	305,163	5,571,856	1,825.9	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	10,442,038	1,476,965	8,965,073	607.0	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	5,221,019	738,483	4,482,536	607.0	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.600	6.000	(0.400)	(6.7)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.560	6.000	(0.440)	(7.3)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.160	12.000	(0.840)	(7.0)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.580	6.000	(0.420)	(7.0)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.465	0.500	(0.035)	(7.0)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	24,278	3,692	20,586	557.6	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	1,695,765	989,328	706,437	71.4	4,342,097	2,956,349	1,385,748	46.9
2	LIGHT OIL	1,097,449	989,446	108,003	10.9	3,153,495	3,404,790	(251,295)	(7.4)
3	COAL	32,342,148	35,170,282	(2,828,134)	(8.0)	119,157,022	129,887,151	(10,730,129)	(8.3)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	35,135,362	37,149,056	(2,013,694)	(5.4)	126,652,614	136,248,290	(9,595,676)	(7.0)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	46,126	22,352	23,774	106.4	118,149	66,685	51,464	77.2
9	LIGHT OIL	28,929	20,583	8,346	40.5	81,816	74,116	7,700	10.4
10	COAL	1,602,777	1,699,083	(96,306)	(5.7)	6,001,512	6,259,105	(257,593)	(4.1)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,677,832	1,742,018	(64,186)	(3.7)	6,201,477	6,399,906	(198,429)	(3.1)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	103,182	52,621	50,561	96.1	259,058	155,015	104,043	67.1
16	LIGHT OIL (BBL)	54,428	36,699	17,729	48.3	152,478	124,483	27,995	22.5
17	COAL (TON)	776,009	762,812	13,197	1.7	2,866,390	2,805,860	60,530	2.2
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	651,531	332,617	318,914	95.9	1,635,289	979,858	655,431	66.9
22	LIGHT OIL	315,743	212,644	103,099	48.5	880,455	721,851	158,604	22.0
23	COAL	17,113,261	17,509,618	(396,357)	(2.3)	63,559,278	64,125,745	(566,467)	(0.9)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	18,080,535	18,054,879	25,656	0.1	66,075,022	65,827,454	247,568	0.4
	GENERATION MIX (% MWH)								
28	HEAVY OIL	2.75	1.28	1.47	-	1.91	1.04	0.87	-
29	LIGHT OIL	1.72	1.18	0.54	-	1.32	1.16	0.16	-
30	COAL	95.53	97.54	(2.01)	-	96.77	97.80	(1.03)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	16.43	18.80	(2.37)	(12.6)	16.76	19.07	(2.31)	(12.1)
36	LIGHT OIL ($/BBL)	20.16	26.96	(6.80)	(25.2)	20.68	27.35	(6.67)	(24.4)
37	COAL ($/TON)	41.68	46.11	(4.43)	(9.6)	41.57	46.29	(4.72)	(10.2)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.60	2.97	(0.37)	(12.5)	2.66	3.02	(0.36)	(11.9)
42	LIGHT OIL	3.48	4.65	(1.17)	(25.2)	3.58	4.72	(1.14)	(24.2)
43	COAL	1.89	2.01	(0.12)	(6.0)	1.87	2.03	(0.16)	(7.9)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.94	2.06	(0.12)	(5.8)	1.92	2.07	(0.15)	(7.2)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JULY, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	14,125	14,881	(756)	(5.1)	13,841	14,694	(853)	(5.8)
49	LIGHT OIL	10,914	10,331	583	5.6	10,761	9,739	1,022	10.5
50	COAL	10,677	10,305	372	3.6	10,591	10,245	346	3.4
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,776	10,364	412	4.0	10,655	10,286	369	3.6
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.68	4.43	(0.75)	(16.9)	3.68	4.43	(0.75)	(16.9)
56	LIGHT OIL	3.79	4.81	(1.02)	(21.2)	3.85	4.59	(0.74)	(16.1)
57	COAL	2.02	2.07	(0.05)	(2.4)	1.99	2.08	(0.09)	(4.3)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.09	2.13	(0.04)	(1.9)	2.04	2.13	(0.09)	(4.2)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: JULY, 1998

SCHEDULE A4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	4781	20.1	85.1	59.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	6723	28.2	100.0	62.4	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	6916	29.0	100.0	61.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	7711	25.3	99.9	52.8	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	9122	18.3	75.3	55.2	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	35253	23.2	89.5	57.5	15648	HVY.OIL	87259	6321821	551635.8	1366971	3.88	15.67
GAN.#1	114	49298	58.1	71.6	69.1	11984	COAL	30819	19169542	590786.1	1308024	2.65	42.44
GAN.#2	108	38478	47.9	61.4	61.6	13982	COAL	26744	20116781	538003.2	1135073	2.95	42.44
GAN.#3	155	81032	70.3	80.9	71.7	11982	COAL	51674	18789480	970927.6	2193155	2.71	42.44
GAN.#4	169	83369	66.3	77.4	72.8	11721	COAL	51526	18964061	977142.2	2186874	2.62	42.44
GAN.#5	227	122802	72.7	80.9	84.5	10082	COAL	50101	24712060	1238098.9	2126394	1.73	42.44
GAN.#6	362	195619	72.6	83.0	73.8	11037	COAL	90598	23831640	2159098.9	3845173	1.97	42.44
GANNON STA.	1135	570598	67.6	78.3	73.9	11346	COAL	301462	21475532	6474056.9	12794693	2.24	42.44
B.B.#1	421	175586	56.1	68.0	77.8	10349	COAL	80189	22660260	1817103.6	3249223	1.85	40.52
B.B.#2	416	224265	72.5	86.2	77.9	10219	COAL	100616	22778260	2291857.4	4076916	1.82	40.52
B.B.#3	428	248482	78.0	89.2	78.0	10596	COAL	116233	22652960	2633021.5	4709710	1.90	40.52
B.B. 1 - 3	1265	648333	68.9	81.2	77.9	10399	COAL	297038	22697374	6741982.5	12035849	1.86	40.52
B.B.#4	442	278091	84.6	91.4	84.8	10062	COAL	131626	21258966	2798232.7	5502878	1.98	41.81
B.B. STA.	1707	926424	72.9	83.8	79.7	10298	COAL	428664	22255695	9540215.2	17538727	1.89	40.91
SEB-PHIL. #1(HVY OIL)	17	5387	42.6	99.0	83.3	9188	HVY.OIL	7889	6273786	49493.9	162900	3.02	20.65
SEB-PHIL. #2(HVY OIL)	17	5486	43.4	99.5	84.8	9187	HVY.OIL	8034	6273438	50400.8	165894	3.02	20.65
SEB-PHILLIPS TOTAL	34	10873	43.0	99.3	84.1	9187	HVY.OIL	15923	6273611	99894.7	328794	3.02	20.65
POLK COAL	250	105755	56.9	61.3	92.7	10392	COAL	45883	23952000	1098989.6	2008728	1.90	43.78
POLK OIL	225	19693	11.8	20.1	58.5	9128	LGT.OIL	30981	5802350	179762.6	644255	3.27	20.80
POLK TOTAL	250	125448	68.7	81.4	-	10193	-	-	-	1278752.2	2652983	2.11	-
GAN.C.T.#1	15	506	4.5	100.0	99.2	20298	LGT.OIL	1765	5819093	10270.7	34116	6.74	19.33
B.B.C.T.#1	15	860	7.7	85.1	98.9	19729	LGT.OIL	2927	5796720	16967.0	56574	6.58	19.33
B.B.C.T.#2	65	7870	16.3	100.0	99.2	13817	LGT.OIL	18755	5798054	108742.5	362504	4.61	19.33
B.B.C.T.#3	65	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	160	9236	7.8	98.6	58.9	14723	LGT.OIL	23447	5799471	135980.2	453194	4.91	19.33
TOT. COAL (GN,BB,POLK)	2842	1602777	75.8	80.0	78.6	10677	COAL	776009	22052917	17113261.7	32342148	2.02	41.68
SYSTEM	3490	1677832	64.6	81.6	76.5	10776	-	-	-	18080535.0	35135362	2.09	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

		CURRENT MONTH				PERIOD TO DATE			
	HEAVY OIL (1)	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	PURCHASES:								
2	UNITS (BBL)	221,301	52,621	168,680	320.6	242,093	155,015	87,078	56.2
3	UNIT COST ($/BBL)	16.01	17.83	(1.82)	(10.2)	15.27	17.86	(2.59)	(14.5)
4	AMOUNT ($)	3,542,087	938,067	2,604,020	277.6	3,695,695	2,768,659	927,036	33.5
5	BURNED:								
6	UNITS (BBL)	103,182	52,621	50,561	96.1	259,058	155,015	104,043	67.1
7	UNIT COST ($/BBL)	16.43	18.80	(2.37)	(12.6)	16.76	19.07	(2.31)	(12.1)
8	AMOUNT ($)	1,695,765	989,328	706,437	71.4	4,342,097	2,956,349	1,385,748	46.9
9	ENDING INVENTORY:								
10	UNITS (BBL)	173,629	139,530	34,099	24.4	173,629	139,530	34,099	24.4
11	UNIT COST ($/BBL)	16.03	17.83	(1.80)	(10.1)	16.03	17.83	(1.80)	(10.1)
12	AMOUNT ($)	2,784,107	2,487,142	296,965	11.9	2,784,107	2,487,142	296,965	11.9
13									
14	DAYS SUPPLY:	146	207	(61)	(29.5)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	65,886	48,318	17,568	36.4	185,633	168,871	16,762	9.9
17	UNIT COST ($/BBL)	18.62	26.82	(8.20)	(30.6)	19.14	27.11	(7.97)	(29.4)
18	AMOUNT ($)	1,226,622	1,295,777	(69,155)	(5.3)	3,552,576	4,578,815	(1,026,239)	(22.4)
19	BURNED:								
20	UNITS (BBL)	54,428	36,699	17,729	48.3	152,478	124,483	27,995	22.5
21	UNIT COST ($/BBL)	20.16	26.96	(6.80)	(25.2)	20.68	27.35	(6.67)	(24.4)
22	AMOUNT ($)	1,097,449	989,446	108,003	10.9	3,153,495	3,404,790	(251,295)	(7.4)
23	ENDING INVENTORY:								
24	UNITS (BBL)	75,596	60,844	14,752	24.2	75,596	60,844	14,752	24.2
25	UNIT COST ($/BBL)	19.86	27.13	(7.27)	(26.8)	19.86	27.13	(7.27)	(26.8)
26	AMOUNT ($)	1,501,464	1,650,562	(149,098)	(9.0)	1,501,464	1,650,562	(149,098)	(9.0)
27									
28	DAYS SUPPLY: NORMAL	79	65	14	21.5	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	11	9	2	22.2	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	690,493	777,500	(87,007)	(11.2)	2,840,374	2,974,500	(134,126)	(4.5)
32	UNIT COST ($/TON)	41.26	45.68	(4.42)	(9.7)	40.89	45.74	(4.85)	(10.6)
33	AMOUNT ($)	28,488,375	35,517,431	(7,029,056)	(19.8)	116,151,530	136,066,957	(19,915,427)	(14.6)
34	BURNED:								
35	UNITS (TONS)	776,009	762,812	13,197	1.7	2,866,390	2,805,860	60,530	2.2
36	UNIT COST ($/TON)	41.68	46.11	(4.43)	(9.6)	41.57	46.29	(4.72)	(10.2)
37	AMOUNT ($)	32,342,148	35,170,282	(2,828,134)	(8.0)	119,157,022	129,887,151	(10,730,129)	(8.3)
38	ENDING INVENTORY:								
39	UNITS (TONS)	606,313	696,989	(90,676)	(13.0)	606,313	696,989	(90,676)	(13.0)
40	UNIT COST ($/TON)	40.76	45.97	(5.21)	(11.3)	40.76	45.97	(5.21)	(11.3)
41	AMOUNT ($)	24,714,399	32,039,866	(7,325,467)	(22.9)	24,714,399	32,039,866	(7,325,467)	(22.9)
42									
43	DAYS SUPPLY:	25	30	(5)	(16.7)	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY, 1998

	OTHER		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	11,645
FUEL ANALYSIS	0
LUBE OIL	0
TOTAL	11,645

(2)*RECONCILIATION - LIGHT OIL*
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(13,234)	(255,896)
OTHER USAGE	(1,905)	(38,636)
TOTAL	(15,139)	(294,532)

(3)RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
PROPANE IGNITION	5,236
IGNITION	244,251
FUEL ANALYSIS	28,664
AERIAL SURVEY ADJ.	44,501
ADDITIVES	123,006
TOTAL	445,658

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JULY, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	73,058.0	0.0	73,058.0	1.562	2.136	1,141,200.00	1,560,800.00	335,680.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,756.0	0.0	5,756.0	1.800	1.800	103,600.00	103,600.00	
VARIOUS	SEPARATED	SCH. -D	35,228.0	0.0	35,228.0	1.478	1.720	520,500.00	606,000.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	24,431.0	0.0	24,431.0	2.376	3.184	580,500.00	778,000.00	
LAKELAND/FMPA		SCH. -D	63,240.0	0.0	63,240.0	1.504	1.563	951,000.00	988,400.00	
VARIOUS	JURISDICTIONAL	SCH. -J	5,952.0	0.0	5,952.0	2.354	2.354	140,100.00	140,100.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	207,665.0	0.0	207,665.0	1.655	2.011	3,436,900.00	4,176,900.00	335,680.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(92,800.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						335,680.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	207,665.0	0.0	207,665.0	1.772	2.011	3,679,780.00	4,176,900.00	335,680.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	6,531.0	0.0	6,531.0	2.175	3.263	142,076.95	213,108.47	56,825.22
FLA. PWR. & LIGHT		ECON.-C	6,864.0	0.0	6,864.0	1.985	2.594	136,269.65	178,030.34	33,408.56
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	284.0	0.0	284.0	1.787	2.666	5,074.01	7,570.34	1,997.06
CITY OF HOMESTEAD		ECON.-C	335.0	0.0	335.0	1.724	2.208	5,774.07	7,397.23	1,298.52
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	115.0	0.0	115.0	1.747	2.438	2,009.15	2,803.26	635.29
CITY OF NEW SMYRNA BCH.		ECON.-C	71.0	0.0	71.0	2.359	4.872	1,674.94	3,459.47	1,427.62
ORLANDO UTIL. COMM.		ECON.-C	3,170.0	0.0	3,170.0	1.671	1.815	52,963.45	57,541.30	3,662.28
SEMINOLE ELECTRIC CO-OP		ECON.-C	1,727.0	0.0	1,727.0	1.768	2.319	30,538.15	40,056.35	7,614.56
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	40.0	0.0	40.0	2.156	4.879	862.48	1,951.65	871.34
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	10,659.0	0.0	10,659.0	1.667	1.949	177,697.42	207,747.82	24,040.32
SONAT		ECON.-C	491.0	0.0	491.0	1.872	7.701	9,189.19	37,813.50	22,899.45
THE ENERGY AUTHORITY		ECON.-C	1,540.0	0.0	1,540.0	3.226	7.164	49,683.72	110,323.25	48,511.62
NP ENERGY INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	2,052.0	0.0	2,052.0	2.470	8.520	50,683.20	174,824.49	99,313.03
TENNESSEE VALLEY AUTHORITY		ECON.-C	5,220.0	0.0	5,220.0	3.069	18.686	160,217.60	975,389.99	652,137.91
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA-E	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	13,377.0	0.0	13,377.0	1.685	1.831	225,395.30	244,973.70	
REEDY CREEK	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.508	1.810	224,390.40	269,328.00	
WAUCHULA	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.508	1.810	56,097.60	67,332.00	
FT. MEADE	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.508	1.810	56,097.60	67,332.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	62,938.0	0.0	62,938.0	2.005	2.644	1,261,906.90	1,664,080.72	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	4,541.0	432.1	4,108.9	2.322	2.322	95,399.11	95,399.11	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	604.0	0.0	604.0	1.665	1.665	10,057.31	10,057.31	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	9,329.0	0.0	9,329.0	2.224	2.224	207,441.13	207,441.13	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	4,640.0	0.0	4,640.0	2.468	2.468	114,533.00	114,533.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF GAINESVILLE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JULY 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FMPA	SCH. -D	63,240.0	63,240.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	4,419.0	0.0	4,419.0	2.240	2.821	98,974.12	124,677.96	20,563.07 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	3,041.0	0.0	3,041.0	2.655	3.189	80,742.15	96,965.27	12,978.50 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	299.0	0.0	299.0	2.018	2.381	6,033.57	7,120.39	869.46 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	214.0	0.0	214.0	1.927	2.536	4,123.33	5,427.85	1,043.62 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	18.0	0.0	18.0	2.178	3.336	392.06	600.54	166.78 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	414.0	0.0	414.0	2.733	2.972	11,315.00	12,302.15	789.72 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO HOMESTEAD	ECON.-C	27.0	0.0	27.0	1.854	2.224	500.49	600.47	79.98 *
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	484.0	0.0	484.0	1.967	2.363	9,522.65	11,438.04	1,532.31 *
HARDEE PWR. PARTNERS TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	25.0	0.0	25.0	1.874	2.370	468.42	592.57	99.32 *
HARDEE PWR. PARTNERS TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ENGY. AUTH.	ECON.-C	44.0	0.0	44.0	2.465	3.062	1,084.60	1,347.20	210.08 *
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO TVA	ECON.-C	401.0	0.0	401.0	4.411	6.736	17,688.11	27,013.04	7,459.94 *
HARDEE PWR. PARTNERS TO SONAT	ECON.-C	594.0	0.0	594.0	3.612	4.178	21,457.56	24,817.66	2,688.08 *
ADJUSTMENTS TO JUNE 1998									
HARDEE POWER PARTNERS SEPAR.	CONTRACT	(59,906.0)	0.0	(59,906.0)	2.011	2.633	(1,204,709.66)	(1,577,324.98)	
HARDEE POWER PARTNERS SEPAR.	CONTRACT	59,906.0	0.0	59,906.0	2.005	2.644	1,201,115.30	1,583,914.64	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	(6,729.0)	0.0	(6,729.0)	2.421	3.051	(162,884.59)	(205,328.82)	(33,955.38)*
HARDEE PWR. PARTNERS TO FPC	ECON.-C	6,729.0	0.0	6,729.0	2.421	3.055	162,884.59	205,554.85	34,136.21 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	(430.0)	0.0	(430.0)	2.293	2.770	(9,861.86)	(11,912.39)	(1,640.42)*
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	430.0	0.0	430.0	2.293	2.993	9,861.86	12,868.30	2,405.15 *
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	(1,072.0)	0.0	(1,072.0)	4.071	42.032	(43,641.12)	(450,587.54)	(325,557.14)*
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	1,072.0	0.0	1,072.0	4.071	40.187	43,641.12	430,808.50	309,733.90 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	(73.0)	0.0	(73.0)	2.060	2.473	(1,503.75)	(1,805.41)	(241.33)*
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	73.0	0.0	73.0	2.060	2.474	1,503.75	1,806.31	242.05 *
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	(71.0)	0.0	(71.0)	1.916	2.679	(1,360.58)	(1,902.24)	(433.33)*
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	71.0	0.0	71.0	1.916	2.708	1,360.58	1,922.89	449.85 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	(510.0)	0.0	(510.0)	1.906	2.167	(9,719.66)	(11,052.70)	(1,066.43)*
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	510.0	0.0	510.0	1.906	2.168	9,719.66	11,058.99	1,071.46 *
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	(2,145.0)	0.0	(2,145.0)	3.340	3.699	(71,644.46)	(79,347.06)	(6,162.08)*
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	2,145.0	0.0	2,145.0	3.340	3.701	71,644.46	79,386.06	6,193.28 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	(189.0)	0.0	(189.0)	1.947	2.470	(3,679.77)	(4,667.54)	(790.22)*
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	189.0	0.0	189.0	1.947	2.486	3,679.77	4,698.99	815.38 *
SUB-TOTAL ECONOMY POWER SALES		49,079.0	0.0	49,079.0	2.194	4.712	1,077,016.04	2,312,421.79	988,324.59
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		35,697.0	0.0	35,697.0	1.574	1.818	561,980.90	648,965.70	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		6,145.0	432.1	4,712.9	2.238	2.238	105,456.42	105,456.42	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		13,969.0	0.0	13,969.0	2.305	2.305	321,974.13	321,974.13	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		62,938.0	0.0	62,938.0	1.999	2.654	1,258,312.54	1,670,670.38	
SUB-TOTAL OTHER SCHEDULE D POWER SALES		63,240.0	63,240.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS	-	230,068.0	63,672.1	166,395.9	1.998	3.041	3,324,740.03	5,059,488.42	988,324.59
LESS VARIABLE O & M COSTS	-						(65,295.33)		
LESS VARIABLE O & M COSTS - HARDEE	-						(1,397.20)		
LESS TRANSMISSION COSTS SCH.-D (SEP.)							(23,651.22)		
PLUS 80% OF ECON. ENERGY SALES PROFIT	-						988,324.59		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL 80% OF ECON. ENERGY SALES PROFITS	-	230,068.0	63,672.1	166,395.9	2.538	3.041	4,222,720.87	5,059,488.42	988,324.59
CURRENT MONTH: DIFFERENCE	-	22,403.0	63,672.1	(41,269.1)	0.766	1.030	542,940.87	882,588.42	652,644.59
DIFFERENCE %	-	10.8	0.0	(19.9)	43.2	51.2	14.8	21.1	194.4
PERIOD TO DATE: ACTUAL	-	857,983.0	233,641.6	624,341.4	2.493	2.977	15,566,141.66	18,586,371.98	4,590,353.84
ESTIMATED	-	830,743.0	0.0	830,743.0	1.792	2.031	14,887,220.00	16,868,800.00	1,583,920.00
DIFFERENCE	-	27,240.0	233,641.6	(206,401.6)	0.701	0.946	678,921.66	1,717,571.98	3,006,433.84
DIFFERENCE %	-	3.3	0.0	(24.8)	39.1	46.6	4.6	10.2	189.8

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $68,491.58 HAS BEEN EXCLUDED.
** SEC 60% REPORTED FOR THE MONTH OF JUNE 1998 OF $813,426.52 HAS BEEN REVISED TO $764,925.33.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JULY, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	7,746.0	0.0	4,760.0	2,986.0	5.161	5.161	154,100.00
HARDEE POWER PARTNERS	IPP	68,681.0	0.0	0.0	68,681.0	3.022	3.022	2,075,200.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	76,427.0	0.0	4,760.0	71,667.0	3.111	3.111	2,229,300.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	109,567.0	0.0	0.0	109,567.0	2.637	2.637	2,889,271.22
HARDEE PWR. PART.-FOR OTHERS	IPP	9,980.0	0.0	0.0	9,980.0	2.477	2.491	247,166.38
FLA. POWER CORP.	SCH.-Ja	446.0	0.0	434.8	11.2	5.503	5.503	616.35
FLA. POWER CORP.	SCH.-Jc	7,006.0	0.0	0.0	7,006.0	2.481	2.481	173,832.15
FLA. POWER & LIGHT	SCH.-Ja	6,177.0	0.0	4,195.7	1,981.3	6.986	6.986	138,413.48
FLA. POWER & LIGHT	SCH.-Jc	5,190.0	0.0	0.0	5,190.0	3.517	3.517	182,547.85
CITY OF LAKELAND	SCH.-Ja	1,058.0	0.0	896.1	161.9	4.681	4.681	7,578.92
CITY OF LAKELAND	SCH.-Jc	100.0	0.0	0.0	100.0	3.400	3.400	3,400.00
ORLANDO UTIL. COMM.	SCH.-Ja	6,858.0	0.0	6,554.0	304.0	7.256	7.256	22,057.04
ORLANDO UTIL. COMM.	SCH.-Jc	5,290.0	0.0	0.0	5,290.0	3.971	3.971	210,069.25
SEMINOLE ELEC. CO-OP	SCH.-Ja	1,121.0	0.0	1,121.0	0.0	0.000	0.000	0.00
SEMINOLE ELEC. CO-OP	SCH.-Jc	54.0	0.0	0.0	54.0	7.500	7.500	4,050.00
THE ENERGY AUTHORITY	SCH.-Ja	1,108.0	0.0	970.5	137.5	7.553	7.553	10,385.35
REEDY CREEK	SCH.-Ja	85.0	0.0	85.0	0.0	0.000	0.000	0.00
PECO	SCH.-Ja	963.0	0.0	643.0	320.0	4.191	4.191	13,411.09
PECO	SCH.-Jc	1,097.0	0.0	0.0	1,097.0	2.429	2.429	26,643.00
TALLAHASSEE	SCH.-Ja	244.0	0.0	244.0	0.0	0.000	0.000	0.00
CITY OF LAKE WORTH	SCH.-Ja	259.0	0.0	259.0	0.0	0.000	0.000	0.00
CITY OF LAKE WORTH	SCH.-Jc	27.0	0.0	0.0	27.0	9.411	9.411	2,541.04
VIRGINIA ELECTRIC POWER	SCH.-Ja	1,200.0	0.0	1,200.0	0.0	0.000	0.000	0.00
PECO	OTHER	39,215.0	39,215.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO JUNE 1998:								
HARDEE PWR.PART.-NATIVE	IPP	(92,355.0)	0.0	0.0	(92,355.0)	2.408	2.408	(2,223,891.67)
HARDEE PWR.PART.-NATIVE	IPP	92,355.0	0.0	0.0	92,355.0	2.903	2.903	2,680,993.18
SEMINOLE ELEC. CO-OP	SCH.-Jc	(12.0)	0.0	0.0	(12.0)	15.484	15.484	(1,858.12)
SEMINOLE ELEC. CO-OP	SCH.-Jc	12.0	0.0	0.0	12.0	5.571	5.571	668.54
THE ENERGY AUTHORITY	SCH.-Jc	(4,374.0)	0.0	(3,213.7)	(1,160.3)	22.985	22.985	(266,690.93)
THE ENERGY AUTHORITY	SCH.-Jc	4,374.0	0.0	3,213.7	1,160.3	22.744	22.744	263,895.95
TOTAL		221,070.0	63,240.0	16,603.1	141,226.9	3.105	3.114	4,385,100.07
CURRENT MONTH:								
DIFFERENCE	-	144,643.0	63,240.0	11,843.1	69,559.9	(0.006)	0.003	2,155,800.07
DIFFERENCE %	-	189.3	0.0	248.8	97.1	(0.2)	0.1	96.7
PERIOD TO DATE:								
ACTUAL	-	657,625.0	232,131.0	53,058.9	372,435.1	3.289	3.301	12,249,629.05
ESTIMATED	-	230,017.0	0.0	12,305.0	217,712.0	3.119	3.119	6,790,100.00
DIFFERENCE	-	427,608.0	232,131.0	40,753.9	154,723.1	0.170	0.182	5,459,529.05
DIFFERENCE %	-	185.9	0.0	331.2	71.1	5.5	5.8	80.4

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JULY, 1998

SCHEDULE A8

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	41,305.0	0.0	0.0	41,305.0	2.366	2.366	977,100.00
TOTAL	-	41,305.0	0.0	0.0	41,305.0	2.366	2.366	977,100.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	1,988.0	0.0	0.0	1,988.0	3.743	3.743	74,414.55
McKAY BAY REFUSE	COGEN.	9,217.0	0.0	0.0	9,217.0	1.835	1.835	169,168.17
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	21.0	0.0	0.0	21.0	9.673	9.673	2,031.26
HILLSBOROUGH COUNTY	COGEN.	19,171.0	0.0	0.0	19,171.0	1.833	1.833	351,335.71
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	691.0	0.0	0.0	691.0	3.630	3.630	25,081.77
FARMLAND HYDRO LP	COGEN.	70.0	0.0	0.0	70.0	5.045	5.045	3,531.60
IMC-AGRICO-S. PIERCE	COGEN.	746.0	0.0	0.0	746.0	3.783	3.783	28,224.61
AUBURNDALE POWER PARTNERS	COGEN.	310.0	0.0	0.0	310.0	5.815	5.815	18,026.50
ORANGE COGENERATION L.P.	COGEN.	6,394.0	0.0	0.0	6,394.0	1.832	1.832	117,141.61
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	1,170.0	(1,170.0)	7.628	7.628	(89,244.28)
SUB-TOTAL FOR JULY, 1998		38,608.0	0.0	1,170.0	37,438.0	1.869	1.869	699,711.50
ADJUSTMENTS TO MAY, 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(10,163.0)	0.0	0.0	(10,163.0)	1.772	1.772	(180,041.69)
		10,163.0	0.0	0.0	10,163.0	1.776	1.776	180,506.14
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(19,634.0)	0.0	0.0	(19,634.0)	1.777	1.777	(348,827.38)
		19,634.0	0.0	0.0	19,634.0	1.781	1.781	349,743.62
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.							
FARMLAND HYDRO LP	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	1.816	1.816	(142,427.12)
		7,843.0	0.0	0.0	7,843.0	1.824	1.824	143,053.64
AS AVAILABLE ASSIGNMENT	COGEN.							
SUB-TOTAL FOR MAY 1998 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	2,007.21
GRAND TOTAL CURRENT MONTH:		38,608.0	0.0	1,170.0	37,438.0	1.874	1.874	701,718.71
DIFFERENCE	-	(2,697.0)	0.0	1,170.0	(3,867.0)	(0.492)	(0.492)	(275,381.29)
DIFFERENCE %	-	(6.5)	0.0	0.0	(9.4)	(20.8)	(20.8)	(28.2)
PERIOD TO DATE:								
ACTUAL		157,697.0	0.0	2,155.7	155,541.3	1.764	1.764	2,744,316.62
ESTIMATED		156,471.0	0.0	0.0	156,471.0	2.319	2.319	3,628,400.00
DIFFERENCE	-	1,226.0	0.0	2,155.7	(929.7)	(0.555)	(0.555)	(884,083.38)
DIFFERENCE %	-	0.8	0.0	0.0	(0.6)	(23.9)	(23.9)	(24.4)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JULY, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	8,039.0	4.472	359,500.00	5.134	412,700.00	53,200.00
TOTAL	-	8,039.0	4.472	359,500.00	5.134	412,700.00	53,200.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	50.0	1.893	946.25	2.400	1,200.00	253.75
FLA. PWR. & LIGHT	ECON.-C	549.0	3.119	17,124.66	3.129	17,177.58	52.92
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	68.0	3.597	2,446.15	4.173	2,837.80	391.65
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	44.0	3.686	1,621.90	3.816	1,679.20	57.30
ORLANDO UTIL. COMM.	ECON.-C	350.0	3.034	10,618.18	3.580	12,529.91	1,911.73
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	25.0	3.347	836.73	3.894	973.46	136.73
PECO	ECON.-C	265.0	3.081	8,164.85	4.172	11,054.70	2,889.85
THE ENERGY AUTHORITY	ECON.-C	89.0	3.786	3,369.96	4.840	4,307.44	937.48
ADJUSTMENTS TO JUNE 1998							
FLA. PWR. & LIGHT	ECON.-C	(62.0)	3.207	(1,988.56)	3.516	(2,180.16)	(191.60)
FLA. PWR. & LIGHT	ECON.-C	62.0	3.207	1,988.27	3.516	2,180.16	191.89
TOTAL	-	1,440.0	3.134	45,128.39	3.594	51,760.09	6,631.70
CURRENT MONTH:							
DIFFERENCE	-	(6,599.0)	(1.338)	(314,371.61)	(1.540)	(360,939.91)	(46,568.30)
DIFFERENCE %	-	(82.1)	(29.9)	(87.4)	(30.0)	(87.5)	(87.5)
PERIOD TO DATE:							
ACTUAL		3,691.0	3.087	113,933.85	3.511	129,587.47	15,653.62
ESTIMATED		19,822.0	4.288	849,900.00	5.095	1,009,900.00	160,000.00
DIFFERENCE	-	(16,131.0)	(1.201)	(735,966.15)	(1.584)	(880,312.53)	(144,346.38)
DIFFERENCE %	-	(81.4)	(28.0)	(86.6)	(31.1)	(87.2)	(90.2)

COMMISSION SCHEDULES A1 - A9

JUNE 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	35,825,625	35,887,741	(62,116)	(0.2)	1,765,327	1,693,820	71,507	4.2	2.02940	2.11875	(0.08935)	(4.2)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(5,264)	(3,500)	(1,764)	50.4	1,765,327 (a)	1,693,820 (a)	71,507	4.2	(0.00030)	(0.00021)	(0.00009)	42.9
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,765,327 (a)	1,693,820 (a)	71,507	4.2	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,765,327 (a)	1,693,820 (a)	71,507	4.2	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	35,820,361	35,884,241	(63,880)	(0.2)	1,765,327	1,693,820	71,507	4.2	2.02911	2.11854	(0.08943)	(4.2)
6. Fuel Cost of Purchased Power - Firm (A7)	3,471,322	2,099,300	1,372,022	65.4	110,882	68,827	42,055	61.1	3.13065	3.05011	0.08054	2.6
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	8,826	203,400	(194,574)	(95.7)	257	4,757	(4,500)	(94.6)	3.43424	4.27580	(0.84156)	(19.7)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	687,723	832,100	(144,377)	(17.4)	38,012	36,523	1,489	4.1	1.80923	2.27829	(0.46906)	(20.6)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	4,167,871	3,134,800	1,033,071	33.0	149,151	110,107	39,044	35.5	2.79440	2.84705	(0.05265)	(1.8)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,914,478	1,803,927	110,551	6.1				
14. Fuel Cost of Economy Sales (A6)	1,448,886	1,397,700	51,186	3.7	75,313	90,584	(15,271)	(16.9)	1.92382	1.54299	0.38083	24.7
15. Gain on Economy Sales - 80% (A6)	3,195,495	488,000	2,707,495	554.8	75,313 (a)	90,584 (a)	(15,271)	(16.9)	4.24295	0.53873	3.70422	687.6
16. Fuel Cost of Sch. D Separ. Sales (A6)	518,802	500,900	17,902	3.6	34,510	34,091	419	1.2	1.50334	1.46930	0.03404	2.3
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	70,922	103,300	(32,378)	(31.3)	4,345	5,920	(1,575)	(26.6)	1.63227	1.74493	(0.11266)	(6.5)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	(27)	0	(27)	0.0	0	0	0	0.0	ERR	0.00000	ERR	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	302,942	135,500	167,442	123.6	12,946	5,760	7,186	124.8	2.34004	2.35243	(0.01239)	(0.5)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	1,401,001	426,900	974,101	228.2	65,915	18,201	47,714	262.2	2.12547	2.34648	(0.22001)	(9.4)
21. Fuel Cost of Other Power Sales (A6)	0	912,500	(912,500)	(100.0)	0	61,200	(61,200)	(100.0)	0.00000	1.49101	(1.49101)	(100.0)
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	6,938,021	3,964,800	2,973,221	75.0	193,029	215,756	(22,727)	(10.5)	3.59429	1.83763	1.75666	95.6
23. Net Inadvertant Interchange					(1,249)	0	(1,249)	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					282	0	282	0.0				
25. Interchange and Wheeling Losses					3,320	3,300	20	0.6				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	33,050,211	35,054,241	(2,004,030)	(5.7)	1,717,162	1,584,871	132,291	8.3	1.92470	2.21180	(0.28710)	(13.0)
27. Net Unbilled	1,758,964 (a)	689,374 (a)	1,069,590	155.2	91,389	31,168	60,221	193.2	0.10243	0.04350	0.05893	135.5
28. Company Use	87,458 (a)	84,048 (a)	3,410	4.1	4,544	3,800	744	19.6	0.00566	0.00571	(0.00005)	(0.9)
29. T & D Losses	1,468,007 (a)	1,730,291 (a)	(262,284)	(15.2)	76,272	78,230	(1,958)	(2.5)	0.09502	0.11757	(0.02255)	(19.2)
30. System KWH Sales	33,050,211	35,054,241	(2,004,030)	(5.7)	1,544,957	1,471,673	73,284	5.0	2.13923	2.38193	(0.24270)	(10.2)
31. Wholesale KWH Sales	(673,965)	(418,863)	(255,102)	60.9	(31,505)	(17,585)	(13,920)	79.2	2.13923	2.38193	(0.24270)	(10.2)
32. Jurisdictional KWH Sales	32,376,246	34,635,378	(2,259,132)	(6.5)	1,513,452	1,454,088	59,364	4.1	2.13923	2.38193	(0.24270)	(10.2)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	32,380,455	34,639,881	(2,259,426)	(6.5)	1,513,452	1,454,088	59,364	4.1	2.13951	2.38224	(0.24273)	(10.2)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	415,407	418,987	(3,580)	(0.9)	1,513,452	1,454,088	59,364	4.1	0.02745	0.02881	(0.00136)	(4.7)
36. Fuel Credit Differential - FMPA Sale	0	(470,500)	470,500	(100.0)	1,513,452	1,454,088	59,364	4.1	0.00000	(0.03236)	0.03236	(100.0)
37. True-up *	(728,854)	(728,854)	0	0.0	1,513,452	1,454,088	59,364	4.1	(0.04816)	(0.05012)	0.00196	(3.9)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	32,067,008	33,859,514	(1,792,506)	(5.3)	1,513,452	1,454,088	59,364	4.1	2.11880	2.32857	(0.20977)	(9.0)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.12056	2.33050	(0.20994)	(9.0)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,513,452	1,454,088	59,364	4.1	(0.00400)	(0.00417)	0.00017	(4.1)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	32,006,417	33,798,923	(1,792,506)	(5.3)	1,513,452	1,454,088	59,364	4.1	2.11656	2.32633	(0.20977)	(9.0)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.117	2.326	(0.209)	(9.0)

* Based on Jurisdictional Sales (a) included for informational purposes only

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JUNE, 1998

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	91,517,252	99,099,234	(7,581,982)	(7.7)	4,523,645	4,657,888	(134,243)	(2.9)	2.02309	2.12756	(0.10447)	(4.9)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(12,072)	(10,500)	(1,572)	15.0	4,523,645 (a)	4,657,888 (a)	(134,243)	(2.9)	(0.00027)	(0.00023)	(0.00004)	17.4
4b. Adjustments to Fuel Cost	0	0	0	0.0	4,523,645 (a)	4,657,888 (a)	(134,243)	(2.9)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	4,523,645 (a)	4,657,888 (a)	(134,243)	(2.9)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	91,505,180	99,088,734	(7,583,554)	(7.7)	4,523,645	4,657,888	(134,243)	(2.9)	2.02282	2.12733	(0.10451)	(4.9)
6. Fuel Cost of Purchased Power - Firm (A7)	7,864,529	4,560,800	3,303,729	72.4	231,208	146,045	85,163	58.3	3.40150	3.12287	0.27863	8.9
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	68,805	490,400	(421,595)	(86.0)	2,251	11,783	(9,532)	(80.9)	3.05664	4.16193	(1.10529)	(26.6)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	2,042,598	2,651,300	(608,702)	(23.0)	118,103	115,166	2,937	2.6	1.72951	2.30216	(0.57265)	(24.9)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	9,975,932	7,702,500	2,273,432	29.5	351,562	272,994	78,568	28.8	2.83760	2.82149	0.01611	0.6
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					4,875,207	4,930,882	(55,675)	(1.1)				
14. Fuel Cost of Economy Sales (A6)	3,203,423	4,092,600	(889,177)	(21.7)	201,696	263,943	(62,247)	(23.6)	1.58824	1.55056	0.03768	2.4
15. Gain on Economy Sales - 80% (A6)	3,602,029	1,248,240	2,353,789	188.6	201,696	263,943 (a)	(62,247)	(23.6)	1.78587	0.47292	1.31295	277.6
16. Fuel Cost of Sch. D Separ. Sales (A6)	1,350,340	1,374,200	(23,860)	(1.7)	94,075	94,331	(256)	(0.3)	1.43539	1.45679	(0.02140)	(1.5)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	219,434	225,200	(5,766)	(2.6)	14,572	13,357	1,215	9.1	1.50586	1.68601	(0.18015)	(10.7)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,909	0	2,909	0.0	75	0	75	0.0	3.87867	0.00000	3.87867	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	600,819	265,200	335,619	126.6	25,637	11,160	14,477	129.7	2.34356	2.37634	(0.03278)	(1.4)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	2,100,310	1,263,300	837,010	66.3	105,227	54,647	50,580	92.6	1.99598	2.31175	(0.31577)	(13.7)
21. Fuel Cost of Other Power Sales (A6)	264,157	2,738,700	(2,474,543)	(90.4)	16,664	185,640	(168,976)	(91.0)	1.58520	1.47527	0.10993	7.5
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	11,343,421	11,207,440	135,981	1.2	457,946	623,078	(165,132)	(26.5)	2.47702	1.79872	0.67830	37.7
23. Net Inadvertant Interchange					273	0	273	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,293	0	1,293	0.0				
25. Interchange and Wheeling Losses					9,184	9,500	(316)	(3.3)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	90,137,691	95,583,794	(5,446,103)	(5.7)	4,409,643	4,298,364	111,339	2.6	2.04410	2.22376	(0.17966)	(8.1)
27. Net Unbilled	5,060,926 (a)	3,169,636 (a)	1,891,290	59.7	247,587	142,535	105,052	73.7	0.11477	0.07374	0.04103	55.6
28. Company Use	245,210 (a)	253,509 (a)	(8,299)	(3.3)	11,996	11,400	596	5.2	0.00621	0.00644	(0.00023)	(3.6)
29. T & D Losses	4,098,032 (a)	4,672,920 (a)	(574,888)	(12.3)	200,481	210,136	(9,655)	(4.6)	0.10376	0.11878	(0.01502)	(12.6)
30. System KWH Sales	90,137,691	95,583,794	(5,446,103)	(5.7)	3,949,579	3,934,233	15,346	0.4	2.28221	2.42954	(0.14733)	(6.1)
31. Wholesale KWH Sales	(1,384,715)	(812,492)	(572,223)	70.4	(60,846)	(33,292)	(27,554)	82.8	2.27577	2.44050	(0.16473)	(6.7)
32. Jurisdictional KWH Sales	88,752,976	94,771,302	(6,018,326)	(6.4)	3,888,733	3,900,941	(12,208)	(0.3)	2.28231	2.42945	(0.14714)	(6.1)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	88,764,514	94,783,623	(6,019,109)	(6.4)	3,888,733	3,900,941	(12,208)	(0.3)	2.28261	2.42976	(0.14715)	(6.1)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	1,257,756	1,269,401	(11,645)	(0.9)	3,888,733	3,900,941	(12,208)	(0.3)	0.03234	0.03254	(0.00020)	(0.6)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(1,502,980)	1,489,801	(99.1)	3,888,733	3,900,941	(12,208)	(0.3)	(0.00034)	(0.03853)	0.03819	(99.1)
37. True-up *	(2,186,562)	(2,186,562)	0	0.0	3,888,733	3,900,941	(12,208)	(0.3)	(0.05623)	(0.05605)	(0.00018)	0.3
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	87,822,529	92,363,482	(4,540,953)	(4.9)	3,888,733	3,900,941	(12,208)	(0.3)	2.25838	2.36772	(0.10934)	(4.6)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.26025	2.36968	(0.10944)	(4.6)
41. GPIF * (Already Adjusted for Taxes)	181,773	181,773	0	0.0	3,888,733	3,900,941	(12,208)	(0.3)	0.00467	0.00466	0.00001	0.2
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	88,004,302	92,545,255	(4,540,953)	(4.9)	3,888,733	3,900,941	(12,208)	(0.3)	2.26492	2.37435	(0.10943)	(4.6)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.265	2.374	(0.109)	(4.6)

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,825,625	35,887,741	(62,116)	(0.2)	91,517,252	99,099,234	(7,581,982)	(7.7)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	6,938,021	3,964,800	2,973,221	75.0	11,343,421	11,207,440	135,981	1.2
3. FUEL COST OF PURCHASED POWER	3,471,322	2,099,300	1,372,022	65.4	7,864,529	4,560,800	3,303,729	72.4
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	687,723	832,100	(144,377)	(17.4)	2,042,598	2,651,300	(608,702)	(23.0)
4. ENERGY COST OF ECONOMY PURCHASES	8,826	203,400	(194,574)	(95.7)	68,805	490,400	(421,595)	(86.0)
5. TOTAL FUEL & NET POWER TRANSACTION	33,055,475	35,057,741	(2,002,266)	(5.7)	90,149,763	95,594,294	(5,444,531)	(5.7)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(5,264)	(3,500)	(1,764)	50.4	(12,072)	(10,500)	(1,572)	15.0
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	33,050,211	35,054,241	(2,004,030)	(5.7)	90,137,691	95,583,794	(5,446,103)	(5.7)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,513,452	1,454,088	59,364	4.1	3,888,733	3,900,941	(12,208)	(0.3)
2. NONJURISDICTIONAL SALES	31,505	17,585	13,920	79.2	60,846	33,292	27,554	82.8
3. TOTAL SALES	1,544,957	1,471,673	73,284	5.0	3,949,579	3,934,233	15,346	0.4
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9796078	0.9880510	(0.0084432)	(0.9)	0.9845943	0.9915379	(0.0069436)	(0.7)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

	CURRENT MONTH				PERIOD TO DATE			
C. TRUE-UP CALCULATION	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. JURISDICTIONAL FUEL REVENUE	35,075,112	33,986,791	1,088,321	3.2	89,908,427	91,123,368	(1,214,941)	(1.3)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,854	728,854	0	0.0	2,186,562	2,186,562	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	181,773	181,773	0	0.0
c. TRANSITION ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
d. OTHER	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,864,557	34,776,236	1,088,321	3.1	92,276,762	93,491,703	(1,214,941)	(1.3)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	33,050,211	35,054,241	(2,004,030)	(5.7)	90,137,691	95,583,794	(5,446,103)	(5.7)
5. JURISDIC. SALES- % TOTAL KWH SALES (LINE B-4)	0.9796078	0.9880510	(0.0084432)	(0.9)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	32,376,246	34,635,378	(2,259,132)	(6.5)	88,752,976	94,771,302	(6,018,326)	(6.4)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	32,380,455	34,639,881	(2,259,426)	(6.5)	88,764,514	94,783,623	(6,019,109)	(6.4)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	424,054	424,054	0	0.0	1,276,755	1,279,755	(3,000)	(0.2)
6D.(LINE 6C x LINE 5)	415,407	418,987	(3,580)	(0.9)	1,257,756	1,269,401	(11,645)	(0.9)
6E. INTEREST ON SEPT. 97 ADJ. ON FUEL CREDIT DIFFERENTIAL-FMPA/LKL SALE	0	0	0	0.0	0	0	0	0.0
6F. FUEL CREDIT DIFFERENTIAL-FMPA SALE	0	(470,500)	470,500	0.0	(13,179)	(1,502,980)	1,502,980	0.0
6G. REVENUE REFUND TRUE-UP ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
6H. OIL BELOW THE DISCHARGE VALVE	0	0	0	0.0	0	0	0	0.0
6I. TRANSMISSION ADJ. (JAN.-NOV. 97)	0	0	0	0.0	0	0	0	0.0
6J. JURISDIC. TOTAL FUEL & NET PWR. INCL. ALL ADJUSTMENTS	32,795,862	34,588,368	(1,792,506)	(5.2)	90,009,091	94,550,044	(4,540,953)	(4.8)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6J)	3,068,695	187,868	2,880,827	1,533.4	2,267,671	(1,058,341)	3,326,012	(314.3)
8. INTEREST PROVISION FOR THE MONTH	15,647	7,176	8,471	118.0	57,375	43,584	13,791	31.6
9. TRUE-UP & INT. PROV. BEG. OF MONTH	8,251,938	7,748,019	503,919	6.5	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,854)	(728,854)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	4,565,019	1,171,802	3,393,217	289.6	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	2,209,531	1,705,612	503,919	29.5	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	4,549,372	1,164,626	3,384,746	290.6	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	6,758,903	2,870,238	3,888,665	135.5	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	3,379,452	1,435,119	1,944,333	135.5	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.500	6.000	(0.500)	(8.3)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.600	6.000	(0.400)	(6.7)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.100	12.000	(0.900)	(7.5)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.550	6.000	(0.450)	(7.5)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.463	0.500	(0.037)	(7.4)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	15,647	7,176	8,471	118.0	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE, 1998

SCHEDULE A3
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	1,458,034	748,849	709,185	94.7	2,646,332	1,967,021	679,311	34.5
2	LIGHT OIL	629,196	802,149	(172,953)	(21.6)	2,056,046	2,415,344	(359,298)	(14.9)
3	COAL	33,738,395	34,336,743	(598,348)	(1.7)	86,814,874	94,716,869	(7,901,995)	(8.3)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	35,825,625	35,887,741	(62,116)	(0.2)	91,517,252	99,099,234	(7,581,982)	(7.7)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	39,405	16,954	22,451	132.4	72,023	44,333	27,690	62.5
9	LIGHT OIL	14,901	17,925	(3,024)	(16.9)	52,887	53,533	(646)	(1.2)
10	COAL	1,711,021	1,658,941	52,080	3.1	4,398,735	4,560,022	(161,287)	(3.5)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,765,327	1,693,820	71,507	4.2	4,523,645	4,657,888	(134,243)	(2.9)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	87,268	39,383	47,885	121.6	155,876	102,394	53,482	52.2
16	LIGHT OIL (BBL)	30,344	29,649	695	2.3	98,050	87,784	10,266	11.7
17	COAL (TON)	814,673	743,203	71,470	9.6	2,090,381	2,043,048	47,333	2.3
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	550,976	248,943	302,033	121.3	983,758	647,241	336,517	52.0
22	LIGHT OIL	176,518	172,101	4,417	2.6	564,712	509,207	55,505	10.9
23	COAL	18,123,064	17,033,061	1,090,003	6.4	46,446,017	46,616,127	(170,110)	(0.4)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	18,850,558	17,454,105	1,396,453	8.0	47,994,487	47,772,575	221,912	0.5
	GENERATION MIX (% MWH)								
28	HEAVY OIL	2.23	1.00	1.23	-	1.59	0.95	0.64	-
29	LIGHT OIL	0.84	1.06	(0.22)	-	1.17	1.15	0.02	-
30	COAL	96.93	97.94	(1.01)	-	97.24	97.90	(0.66)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	16.71	19.01	(2.30)	(12.1)	16.98	19.21	(2.23)	(11.6)
36	LIGHT OIL ($/BBL)	20.74	27.05	(6.31)	(23.3)	20.97	27.51	(6.54)	(23.8)
37	COAL ($/TON)	41.41	46.20	(4.79)	(10.4)	41.53	46.36	(4.83)	(10.4)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.65	3.01	(0.36)	(12.0)	2.69	3.04	(0.35)	(11.5)
42	LIGHT OIL	3.56	4.66	(1.10)	(23.6)	3.64	4.74	(1.10)	(23.2)
43	COAL	1.86	2.02	(0.16)	(7.9)	1.87	2.03	(0.16)	(7.9)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.90	2.06	(0.16)	(7.8)	1.91	2.07	(0.16)	(7.7)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: JUNE, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	13,982	14,683	(701)	(4.8)	13,659	14,600	(941)	(6.4)
49	LIGHT OIL	11,846	9,601	2,245	23.4	10,678	9,512	1,166	12.3
50	COAL	10,592	10,267	325	3.2	10,559	10,223	336	3.3
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,678	10,305	373	3.6	10,610	10,256	354	3.5
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.70	4.42	(0.72)	(16.3)	3.67	4.44	(0.77)	(17.3)
56	LIGHT OIL	4.22	4.48	(0.26)	(5.8)	3.89	4.51	(0.62)	(13.7)
57	COAL	1.97	2.07	(0.10)	(4.8)	1.97	2.08	(0.11)	(5.3)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.03	2.12	(0.09)	(4.2)	2.02	2.13	(0.11)	(5.2)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: JUNE, 1998

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	5658	24.6	100.0	62.0	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	6149	26.7	100.0	64.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	6356	27.6	100.0	63.6	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	7925	26.8	100.0	64.3	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	3133	6.5	38.3	68.2	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	29221	19.9	79.7	65.1	15667	HVY.OIL	72416	6321778	457797.9	1157993	3.96	15.99
GAN.#1	114	51724	63.0	78.8	67.0	12516	COAL	33896	19099139	647384.4	1410424	2.73	41.61
GAN.#2	108	40675	52.3	66.7	63.9	14029	COAL	28886	19755162	570647.6	1201957	2.96	41.61
GAN.#3	155	78650	70.5	88.6	72.2	11946	COAL	50280	18687001	939582.4	2092168	2.66	41.61
GAN.#4	169	88201	72.5	90.9	73.3	11820	COAL	55600	18751040	1042557.8	2313535	2.62	41.61
GAN.#5	227	125609	76.9	86.1	80.9	10554	COAL	54801	24191799	1325734.8	2280289	1.82	41.61
GAN.#6	362	185391	71.1	80.9	73.2	10928	COAL	84934	23852640	2025900.1	3534133	1.91	41.61
GANNON STA.	1135	570250	69.8	82.9	73.1	11489	COAL	308397	21244717	6551807.1	12832506	2.25	41.61
B.B.#1	421	249381	82.3	96.4	82.3	10225	COAL	111358	22897940	2549868.8	4487137	1.80	40.29
B.B.#2	416	227528	76.0	84.8	84.2	10185	COAL	100892	22969560	2317444.8	4065413	1.79	40.29
B.B.#3	428	242590	78.7	88.5	80.2	10276	COAL	109201	22828220	2492864.5	4400221	1.81	40.29
B.B. 1 - 3	1265	719499	79.0	89.9	82.2	10230	COAL	321451	22896734	7360178.1	12952771	1.80	40.29
B.B.#4	442	266439	83.7	91.9	84.3	10221	COAL	122089	22305293	2723230.9	5276047	1.98	43.21
B.B. STA.	1707	985938	80.2	90.4	82.8	10227	COAL	443540	22733934	10083409.0	18228818	1.85	41.10
SEB-PHIL. #1(HVY OIL)	17	5070	41.4	100.0	83.7	9149	HVY.OIL	7394	6273533	46386.5	149374	2.95	20.20
SEB-PHIL. #2(HVY OIL)	17	5114	41.8	99.8	84.9	9150	HVY.OIL	7458	6274068	46792.0	150667	2.95	20.20
SEB-PHILLIPS TOTAL	34	10184	41.6	99.9	84.3	9149	HVY.OIL	14852	6273802	93178.5	300041	2.95	20.20
POLK COAL	250	154833	86.0	91.0	94.5	9609	COAL	62736	23716000	1487847.0	2677071	1.73	42.67
POLK OIL	225	6502	4.0	6.5	62.0	7424	LGT.OIL	8254	5847795	48267.7	183025	2.81	22.17
POLK TOTAL	250	161335	90.0	97.5	-	9521	-	-	-	1536114.7	2860096	1.77	-
GAN.C.T.#1	15	808	7.5	100.0	99.8	19842	LGT.OIL	2755	5819347	16032.3	55650	6.89	20.20
B.B.C.T.#1	15	691	6.4	100.0	98.0	18513	LGT.OIL	2207	5796285	12792.4	44576	6.45	20.20
B.B.C.T.#2	65	6900	14.7	100.0	992.1	14410	LGT.OIL	17128	5804881	99426.0	345945	5.01	20.20
B.B.C.T.#3	65	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	160	8399	7.3	100.0	421.6	15270	LGT.OIL	22090	5805826	128250.7	446171	5.31	20.20
TOT. COAL (GN,BB,POLK)	3092	1711021	76.9	87.7	80.2	10592	COAL	814673	22245813	18123063.1	33738395	1.97	41.41
SYSTEM	3490	1765327	70.3	87.9	95.0	10678	-	-	-	18850557.9	35825625	2.03	-

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL. = SEBRING-PHILLIPS

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)								
1	PURCHASES:								
2	UNITS (BBL)	15,502	39,383	(23,881)	(60.6)	20,792	102,394	(81,602)	(79.7)
3	UNIT COST ($/BBL)	19.33	18.00	1.33	7.4	7.39	17.88	(10.49)	(58.7)
4	AMOUNT ($)	299,648	708,707	(409,059)	(57.7)	153,608	1,830,592	(1,676,984)	(91.6)
5	BURNED:								
6	UNITS (BBL)	87,268	39,383	47,885	121.6	155,876	102,394	53,482	52.2
7	UNIT COST ($/BBL)	16.71	19.01	(2.30)	(12.1)	16.98	19.21	(2.23)	(11.6)
8	AMOUNT ($)	1,458,034	748,849	709,185	94.7	2,646,332	1,967,021	679,311	34.5
9	ENDING INVENTORY:								
10	UNITS (BBL)	55,510	139,530	(84,020)	(60.2)	55,510	139,530	(84,020)	(60.2)
11	UNIT COST ($/BBL)	16.68	17.88	(1.20)	(6.7)	16.68	17.88	(1.20)	(6.7)
12	AMOUNT ($)	926,140	2,494,700	(1,568,560)	(62.9)	926,140	2,494,700	(1,568,560)	(62.9)
13									
14	DAYS SUPPLY:	28	143	(115)	(80.4)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	42,977	40,310	2,667	6.6	119,747	120,553	(806)	(0.7)
17	UNIT COST ($/BBL)	20.70	26.53	(5.83)	(22.0)	19.42	27.23	(7.81)	(28.7)
18	AMOUNT ($)	889,816	1,069,481	(179,665)	(16.8)	2,325,954	3,283,038	(957,084)	(29.2)
19	BURNED:								
20	UNITS (BBL)	30,344	29,649	695	2.3	98,050	87,784	10,266	11.7
21	UNIT COST ($/BBL)	20.74	27.05	(6.31)	(23.3)	20.97	27.51	(6.54)	(23.8)
22	AMOUNT ($)	629,196	802,149	(172,953)	(21.6)	2,056,046	2,415,344	(359,298)	(14.9)
23	ENDING INVENTORY:								
24	UNITS (BBL)	79,277	60,844	18,433	30.3	79,277	60,844	18,433	30.3
25	UNIT COST ($/BBL)	21.03	27.30	(6.27)	(23.0)	21.03	27.30	(6.27)	(23.0)
26	AMOUNT ($)	1,666,823	1,661,215	5,608	0.3	1,666,823	1,661,215	5,608	0.3
27									
28	DAYS SUPPLY: NORMAL	69	52	17	32.7	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	11	9	2	22.2	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	602,386	746,000	(143,614)	(19.3)	2,149,881	2,197,000	(47,119)	(2.1)
32	UNIT COST ($/TON)	42.06	45.95	(3.89)	(8.5)	40.78	45.77	(4.99)	(10.9)
33	AMOUNT ($)	25,335,428	34,277,604	(8,942,176)	(26.1)	87,663,155	100,549,526	(12,886,371)	(12.8)
34	BURNED:								
35	UNITS (TONS)	814,673	743,203	71,470	9.6	2,090,381	2,043,048	47,333	2.3
36	UNIT COST ($/TON)	41.41	46.20	(4.79)	(10.4)	41.53	46.36	(4.83)	(10.4)
37	AMOUNT ($)	33,738,395	34,336,743	(598,348)	(1.7)	86,814,874	94,716,869	(7,901,995)	(8.3)
38	ENDING INVENTORY:								
39	UNITS (TONS)	691,829	682,301	9,528	1.4	691,829	682,301	9,528	1.4
40	UNIT COST ($/TON)	40.65	46.07	(5.42)	(11.8)	40.65	46.07	(5.42)	(11.8)
41	AMOUNT ($)	28,122,514	31,433,972	(3,311,458)	(10.5)	28,122,514	31,433,972	(3,311,458)	(10.5)
42									
43	DAYS SUPPLY:	28	28	0	0.0	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE, 1998

	OTHER		CURRENT MONTH ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	PERIOD TO DATE ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	12,508
LUBE OIL PURCHASES	0
TOTAL	12,508

(2)RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(8,438)	(170,726)
OTHER USAGE	(1,801)	(37,932)
TOTAL	(10,239)	(208,658)

(3)RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
PROPANE IGNITION	1,890
IGNITION	158,218
FUEL ANALYSIS	53,391
AERIAL SURVEY ADJ.	44,501
ADDITIVES	117,080
TOTAL	375,080

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JUNE, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	90,584.0	0.0	90,584.0	1.670	2.343	1,512,700.00	2,122,700.00	488,000.00
VARIOUS	JURISDICTIONAL	SCH. -D	5,920.0	0.0	5,920.0	1.745	1.745	103,300.00	103,300.00	
VARIOUS	SEPARATED	SCH. -D	34,091.0	0.0	34,091.0	1.469	1.710	500,900.00	583,100.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	18,201.0	0.0	18,201.0	2.345	3.154	426,900.00	574,000.00	
LAKELAND/FMPA		SCH. -D	61,200.0	0.0	61,200.0	1.491	1.563	912,500.00	956,600.00	
VARIOUS	JURISDICTIONAL	SCH. -J	5,760.0	0.0	5,760.0	2.352	2.352	135,500.00	135,500.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	215,756.0	0.0	215,756.0	1.665	2.074	3,591,800.00	4,475,200.00	488,000.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(115,000.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						488,000.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	215,756.0	0.0	215,756.0	1.838	2.074	3,964,800.00	4,475,200.00	488,000.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	19,907.0	0.0	19,907.0	2.070	3.194	412,087.67	635,757.82	178,936.12
FLA. PWR. & LIGHT		ECON.-C	6,755.0	0.0	6,755.0	1.723	1.981	116,394.80	133,817.88	13,938.46
CITY OF LAKELAND		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	273.0	0.0	273.0	1.691	2.813	4,616.92	7,679.92	2,450.40
CITY OF HOMESTEAD		ECON.-C	128.0	0.0	128.0	1.629	1.892	2,085.74	2,422.00	269.01
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	94.0	0.0	94.0	1.886	2.892	1,773.08	2,718.87	756.63
CITY OF NEW SMYRNA BCH.		ECON.-C	148.0	0.0	148.0	2.104	4.566	3,113.22	6,757.88	2,915.73
ORLANDO UTIL. COMM.		ECON.-C	13,967.0	0.0	13,967.0	1.653	1.904	230,818.07	265,873.86	28,044.63
SEMINOLE ELECTRIC CO-OP		ECON.-C	2,928.0	0.0	2,928.0	1.700	2.280	49,789.14	66,744.76	13,564.50
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	73.0	0.0	73.0	1.957	5.012	1,428.96	3,658.40	1,783.55
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	13,935.0	0.0	13,935.0	1.614	2.040	224,898.72	284,250.63	47,481.53
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NP ENERGY INC.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KOCH		ECON.-C	3,718.0	0.0	3,718.0	3.208	55.865	119,263.17	2,077,054.04	1,566,232.70
TENNESSEE VALLEY AUTHORITY		ECON.-C	1,640.0	0.0	1,640.0	4.107	72.047	67,357.20	1,181,569.43	891,369.78
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA-E	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	12,910.0	0.0	12,910.0	1.646	1.836	212,479.86	237,001.50	
REEDY CREEK	SEPAR.	SCH. -D	14,400.0	0.0	14,400.0	1.498	1.798	215,712.00	258,912.00	
WAUCHULA	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.498	1.798	53,928.00	64,728.00	
FT. MEADE	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.498	1.798	53,928.00	64,728.00	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	59,906.0	0.0	59,906.0	2.011	2.633	1,204,709.66	1,577,324.98	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	3,783.0	234.0	3,549.0	1.636	1.636	58,072.37	58,072.37	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	796.0	0.0	796.0	1.614	1.614	12,849.41	12,849.41	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	308.0	0.0	308.0	2.194	2.194	6,756.74	6,756.74	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	8,235.0	0.0	8,235.0	2.236	2.236	184,153.29	184,153.29	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	4,350.0	0.0	4,350.0	2.542	2.542	110,570.05	110,570.05	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JUNE, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES	
FMPA	SCH. -D	61,200.0	61,200.0	0.0	0.000	0.000	0.00	0.00		
CITY OF LAKELAND	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00		
HARDEE PWR. PARTNERS TO FPC	ECON.-C	6,729.0	0.0	6,729.0	2.421	3.051	162,884.59	205,328.82	33,955.38	*
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	430.0	0.0	430.0	2.253	2.770	9,861.86	11,912.39	1,640.42	*
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	189.0	0.0	189.0	1.947	2.470	3,679.77	4,687.54	790.22	*
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	73.0	0.0	73.0	2.060	2.473	1,503.75	1,805.41	241.33	*
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	51.0	0.0	51.0	2.569	3.608	1,310.04	1,840.13	424.07	*
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	510.0	0.0	510.0	1.906	2.167	9,719.66	11,052.70	1,066.43	*
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO SEMINOLE	ECON.-C	2,145.0	0.0	2,145.0	3.340	3.699	71,644.46	79,347.06	6,162.08	*
HARDEE PWR. PARTNERS TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO TALLAHASSEE	ECON.-C	57.0	0.0	57.0	2.021	2.728	1,152.25	1,555.00	322.20	*
HARDEE PWR. PARTNERS TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO LAKE WORTH	ECON.-C	71.0	0.0	71.0	1.916	2.679	1,360.58	1,902.24	433.33	*
HARDEE PWR. PARTNERS TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO ENGY. AUTH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00	*
HARDEE PWR. PARTNERS TO KOCH	ECON.-C	1,072.0	0.0	1,072.0	4.071	42.032	43,641.12	450,587.54	325,557.14	*
HARDEE PWR. PARTNERS TO TVA	ECON.-C	420.0	0.0	420.0	3.881	26.852	16,300.26	112,777.40	77,181.76	*
HARDEE PWR. PARTNERS TO FP&L	SCH. -J	53.0	0.0	53.0	2.758	2.758	1,461.64	1,461.64		
ADJUSTMENTS TO MAY 1998										
HARDEE POWER PARTNERS SEPAR.	CONTRACT	(30,060.0)	0.0	(30,060.0)	1.760	2.418	(529,056.00)	(726,850.80)		
HARDEE POWER PARTNERS SEPAR.	CONTRACT	36,069.0	0.0	36,069.0	2.011	2.633	725,347.59	949,696.77		
HARDEE PWR. PARTNERS TO SEMINOLE	SCH. -G	(75.0)	0.0	(75.0)	3.915	3.879	(2,935.88)	(2,909.27)		
HARDEE PWR. PARTNERS TO SEMINOLE	SCH. -G	75.0	0.0	75.0	3.879	3.879	2,909.27	2,909.27		
HARDEE PWR. PARTNERS TO FPC	ECON.-C	(105.0)	0.0	(105.0)	1.881	2.058	(1,975.05)	(2,161.25)	(148.96)	
HARDEE PWR. PARTNERS TO FPC	ECON.-C	102.0	0.0	102.0	1.881	2.047	1,919.05	2,088.74	138.74	
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	(45.0)	0.0	(45.0)	1.881	2.133	(846.45)	(959.96)	(90.81)	
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	45.0	0.0	45.0	1.881	2.115	846.45	951.58	84.10	
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	(41.0)	0.0	(41.0)	1.881	2.243	(771.21)	(919.68)	(118.78)	
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	41.0	0.0	41.0	1.881	2.223	771.21	911.52	112.25	
REEDY CREEK SEPAR.	SCH.-D	(14,880.0)	0.0	(14,880.0)	1.352	1.622	(201,177.60)	(241,353.60)		
REEDY CREEK SEPAR.	SCH.-D	14,880.0	0.0	14,880.0	1.354	1.625	201,475.20	241,800.00		
CITY OF NEW SMYRNA BCH. SEPAR.	SCH.-D	(8,502.0)	0.0	(8,502.0)	1.699	1.843	(144,444.66)	(156,666.51)		
CITY OF NEW SMYRNA BCH. SEPAR.	SCH.-D	8,502.0	0.0	8,502.0	1.700	1.843	144,532.20	156,666.51		
WAUCHULA SEPAR.	SCH.-D	(3,720.0)	0.0	(3,720.0)	1.352	1.622	(50,294.40)	(60,338.40)		
WAUCHULA SEPAR.	SCH.-D	3,720.0	0.0	3,720.0	1.354	1.625	50,368.80	60,450.00		
FT. MEADE SEPAR.	SCH.-D	(3,656.0)	0.0	(3,656.0)	1.352	1.622	(49,429.12)	(59,300.32)		
FT. MEADE SEPAR.	SCH.-D	3,656.0	0.0	3,656.0	1.354	1.625	49,502.24	59,410.00		
SUB-TOTAL ECONOMY POWER SALES		75,313.0	0.0	75,313.0	2.067	7.371	1,556,684.97	5,551,053.65	3,195,494.94	
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		34,510.0	0.0	34,510.0	1.555	1.814	536,581.42	626,037.18		
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		4,579.0	234.0	4,345.0	1.532	1.532	70,221.78	70,221.78		
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		12,846.0	0.0	12,846.0	2.346	2.346	301,341.72	301,341.72		
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		65,915.0	0.0	65,915.0	2.125	2.731	1,401,001.25	1,800,170.95		
SUB-TOTAL OTHER SCH. D POWER SALES		61,200.0	61,200.0	0.0	0.000	0.000	0.00	0.00		
SUB-TOTAL SCHEDULE G POWER SALES-JURISD.		0.0	0.0	0.0	0.000	0.000	(26.61)	(26.61)		
TOTAL INCLUDING VARIABLE O & M COSTS	-	254,463.0	61,434.0	193,029.0	2.004	4.326	3,868,104.53	8,351,098.67	3,195,494.94	
LESS VARIABLE O & M COSTS	-						(106,155.22)			
LESS VARIABLE O & M COSTS - HARDEE	-						(77,644.80)			
LESS TRANSMISSION COSTS SCH. D (SEP.)							(11,776.80)			
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						3,195,494.94			
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	254,463.0	61,434.0	193,029.0	3.594	4.326	6,938,020.87	8,351,098.67	3,195,494.94	
CURRENT MONTH:										
DIFFERENCE	-	38,707.0	61,434.0	(22,727.0)	1.756	2.252	2,973,220.87	3,875,898.67	2,707,494.94	
DIFFERENCE %	-	17.9	0.0	(10.5)	95.5	108.6	75.0	86.6	554.8	
PERIOD TO DATE:										
ACTUAL	-	627,915.0	169,969.5	457,945.5	2.477	2.954	11,343,420.79	13,526,883.56	3,602,029.25	
ESTIMATED	-	623,078.0	0.0	623,078.0	1.799	2.037	11,207,440.00	12,691,900.00	1,248,240.00	
DIFFERENCE	-	4,837.0	169,969.5	(165,132.5)	0.678	0.917	135,980.79	834,983.56	2,353,789.25	
DIFFERENCE %	-	0.8	0.0	(26.5)	37.7	45.0	1.2	6.6	188.6	

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $813,426.52 HAS BEEN EXCLUDED.
** SEC 60% REPORTED FOR THE MONTH OF MAY 1998 OF $778.06 HAS BEEN REVISED TO $832.75.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JUNE, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	4,457.0	0.0	2,994.0	1,463.0	5.161	5.161	75,500.00
HARDEE POWER PARTNERS	IPP	67,364.0	0.0	0.0	67,364.0	3.004	3.004	2,023,800.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	71,821.0	0.0	2,994.0	68,827.0	3.050	3.050	2,099,300.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	92,355.0	0.0	0.0	92,355.0	2.408	2.408	2,223,891.67
HARDEE PWR. PART.-OTHERS	IPP	11,800.0	0.0	0.0	11,800.0	2.694	2.708	317,855.30
FLA. POWER CORP.	SCH.-JC	81.0	0.0	0.0	81.0	2.500	2.500	2,025.00
FLA. POWER & LIGHT	SCH.-JA	1,376.0	0.0	1,172.6	203.4	9.703	9.703	19,736.48
FLA. POWER & LIGHT	SCH.-JC	1,072.0	0.0	0.0	1,072.0	3.829	3.829	41,050.10
ORLANDO UTIL. COMM.	SCH.-JA	3,883.0	0.0	1,708.9	2,174.1	16.385	16.385	356,220.24
ORLANDO UTIL. COMM.	SCH.-JC	1,766.0	0.0	0.0	1,766.0	3.121	3.121	55,115.25
SEMINOLE ELEC. CO-OP	SCH.-JA	397.0	0.0	397.0	0.0	0.000	0.000	0.00
SEMINOLE ELEC. CO-OP	SCH.-JC	12.0	0.0	0.0	12.0	15.484	15.484	1,858.12
THE ENERGY AUTHORITY	SCH.-JC	4,374.0	0.0	3,213.7	1,160.3	22.985	22.985	266,690.93
CITY OF GAINESVILLE	SCH.-JC	25.0	0.0	0.0	25.0	5.872	5.872	1,468.01
REEDY CREEK	SCH.-JC	50.0	0.0	0.0	50.0	8.500	8.500	4,250.00
PECO	SCH.-JA	100.0	0.0	84.5	15.5	6.300	6.300	976.50
CITY OF LAKE WORTH	SCH.-JC	133.0	0.0	133.0	0.0	0.000	0.000	0.00
SONAT	SCH.-JC	240.0	0.0	124.0	116.0	10.000	10.000	11,600.00
PECO	OTHER	37,950.0	37,950.0	0.0	0.0	0.000	0.000	0.00
FLORIDA POWER CORP.	OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO MAY 1998								
HARDEE PWR. PART.-NATIVE	IPP	(53,528.0)	0.0	0.0	(53,528.0)	2.979	2.979	(1,594,796.89)
HARDEE PWR. PART.-NATIVE	IPP	53,528.0	0.0	0.0	53,528.0	3.307	3.307	1,769,928.50
HARDEE PWR. PART.-OTHERS	IPP	(266.0)	0.0	0.0	(266.0)	2.214	2.214	(5,888.84)
HARDEE PWR. PART.-OTHERS	IPP	266.0	0.0	0.0	266.0	2.214	2.214	5,888.84
THE ENERGY AUTHORITY	SCH.-JA	(667.0)	0.0	(8.0)	(659.0)	6.433	6.433	(42,395.00)
THE ENERGY AUTHORITY	SCH.-JA	675.0	0.0	8.0	667.0	6.187	6.187	41,269.76
THE ENERGY AUTHORITY	SCH.-JC	(669.0)	0.0	0.0	(669.0)	4.373	4.373	(29,253.45)
THE ENERGY AUTHORITY	SCH.-JC	679.0	0.0	0.0	679.0	4.138	4.138	28,095.38
KOCK ENERGY TRAD.	SCH.-Ja	(1,145.0)	0.0	(386.0)	(759.0)	8.922	8.922	(67,720.24)
KOCK ENERGY TRAD.	SCH.-Ja	1,179.0	0.0	386.0	793.0	8.002	8.002	63,456.14
TOTAL		178,916.0	61,200.0	6,833.7	110,882.3	3.131	3.160	3,471,321.80
CURRENT MONTH:								
DIFFERENCE	-	107,095.0	61,200.0	3,839.7	42,055.3	0.081	0.110	1,372,021.80
DIFFERENCE %	-	149.1	0.0	128.2	61.1	2.7	3.6	65.4
PERIOD TO DATE:								
ACTUAL	-	436,555.0	168,891.0	36,455.8	231,208.2	3.401	3.416	7,864,528.98
ESTIMATED	-	153,590.0	0.0	7,545.0	146,045.0	3.123	3.123	4,560,800.00
DIFFERENCE	-	282,965.0	168,891.0	28,910.8	85,163.2	0.278	0.293	3,303,728.98
DIFFERENCE %	-	184.2	0.0	383.2	58.3	8.9	9.4	72.4

SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JUNE, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	36,523.0	0.0	0.0	36,523.0	2.278	2.278	832,100.00
TOTAL	-	36,523.0	0.0	0.0	36,523.0	2.278	2.278	832,100.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	1,657.0	0.0	0.0	1,657.0	3.776	3.776	62,568.03
McKAY BAY REFUSE	COGEN.	9,339.0	0.0	0.0	9,339.0	1.722	1.722	160,786.81
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	38.0	0.0	0.0	38.0	13.613	13.613	5,173.08
HILLSBOROUGH COUNTY	COGEN.	19,053.0	0.0	0.0	19,053.0	1.725	1.725	328,721.87
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	328.0	0.0	0.0	328.0	10.877	10.877	35,677.67
FARMLAND HYDRO LP	COGEN.	56.0	0.0	0.0	56.0	15.299	15.299	8,567.37
IMC-AGRICO-S. PIERCE	COGEN.	632.0	0.0	0.0	632.0	8.937	8.937	56,480.14
AUBURNDALE POWER PARTNERS	COGEN.	71.0	0.0	0.0	71.0	10.042	10.042	7,130.04
ORANGE COGENERATION L.P.	COGEN.	7,567.0	0.0	0.0	7,567.0	1.814	1.814	137,269.32
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	728.7	(728.7)	16.007	16.007	(116,644.78)
SUB-TOTAL FOR JUNE, 1998	-	38,741.0	0.0	728.7	38,012.3	1.804	1.804	685,729.55
ADJUSTMENTS FOR APR., 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(10,911.0)	0.0	0.0	(10,911.0)	1.569	1.569	(171,238.92)
MULBERRY PHOSPHATES INC.	COGEN.	10,911.0	0.0	0.0	10,911.0	1.574	1.574	171,723.63
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(19,432.0)	0.0	0.0	(19,432.0)	1.579	1.579	(306,755.91)
CARGILL MILLPOINT	COGEN.	19,432.0	0.0	0.0	19,432.0	1.583	1.583	307,669.85
CF INDUSTRIES INC.	COGEN.							
FARMLAND INDUSTRIES	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	1.603	1.603	(121,633.52)
AS AVAILABLE ASSIGNMENT	COGEN.	7,590.0	0.0	0.0	7,590.0	1.610	1.610	122,228.81
SUB-TOTAL FOR APR., 1998	-	0.0	0.0	0.0	0.0	0.000	0.000	1,993.94
GRAND TOTAL		38,741.0	0.0	728.7	38,012.3	1.809	1.809	687,723.49
CURRENT MONTH:								
DIFFERENCE	-	2,218.0	0.0	728.7	1,489.3	(0.469)	(0.469)	(144,376.51)
DIFFERENCE %	-	6.1	0.0	0.0	4.1	(20.6)	(20.6)	(17.4)
PERIOD TO DATE:								
ACTUAL		119,089.0	0.0	985.7	118,103.3	1.730	1.730	2,042,597.91
ESTIMATED		115,166.0	0.0	0.0	115,166.0	2.302	2.302	2,651,300.00
DIFFERENCE	-	3,923.0	0.0	985.7	2,937.3	(0.572)	(0.572)	(608,702.09)
DIFFERENCE %	-	3.4	0.0	0.0	2.6	(24.8)	(24.8)	(23.0)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF JUNE, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	4,757.0	4.276	203,400.00	5.018	238,700.00	35,300.00
TOTAL	-	4,757.0	4.276	203,400.00	5.018	238,700.00	35,300.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	62.0	3.207	1,988.56	3.516	2,180.16	191.60
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	8.0	4.120	329.59	4.373	349.84	20.25
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	6.0	3.192	191.49	3.644	218.65	27.16
ORLANDO UTIL. COMM.	ECON.-C	55.0	3.847	2,115.93	4.373	2,405.16	289.23
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	126.0	3.291	4,146.90	4.489	5,655.80	1,508.90
ADJUSTMENTS TO MAY 1998							
FLA. PWR. & LIGHT	ECON.-C	(488.0)	3.110	(15,174.37)	3.172	(15,479.75)	(305.38)
FLA. PWR. & LIGHT	ECON.-C	488.0	3.110	15,174.53	3.172	15,479.75	305.22
CITY OF GAINESVILLE	ECON.-C	(70.0)	3.682	(2,577.44)	4.839	(3,387.06)	(809.62)
CITY OF GAINESVILLE	ECON.-C	70.0	3.759	2,631.15	4.839	3,387.06	755.91
TOTAL	-	257.0	3.434	8,826.34	4.206	10,809.61	1,983.27
CURRENT MONTH:							
DIFFERENCE	-	(4,500.0)	(0.842)	(194,573.66)	(0.812)	(227,890.39)	(33,316.73)
DIFFERENCE %	-	(94.6)	(19.7)	(95.7)	(16.2)	(95.5)	(94.4)
PERIOD TO DATE:							
ACTUAL		2,251.0	3.057	68,805.46	3.457	77,827.38	9,021.92
ESTIMATED		11,783.0	4.162	490,400.00	5.068	597,200.00	106,800.00
DIFFERENCE	-	(9,532.0)	(1.105)	(421,594.54)	(1.611)	(519,372.62)	(97,778.08)
DIFFERENCE %	-	(80.9)	(26.5)	(86.0)	(31.8)	(87.0)	(91.6)

COMMISSION SCHEDULES A1 - A9

MAY 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	28,253,753	33,302,458	(5,048,705)	(15.2)	1,428,351	1,563,143	(134,792)	(8.6)	1.97807	2.13048	(0.15241)	(7.2)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,818)	(3,500)	(318)	9.1	1,428,351 (a)	1,563,143 (a)	(134,792)	(8.6)	(0.00027)	(0.00022)	(0.00005)	22.7
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,428,351 (a)	1,563,143 (a)	(134,792)	(8.6)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,428,351 (a)	1,563,143 (a)	(134,792)	(8.6)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	28,249,935	33,298,958	(5,049,023)	(15.2)	1,428,351	1,563,143	(134,792)	(8.6)	1.97780	2.13026	(0.15246)	(7.2)
6. Fuel Cost of Purchased Power - Firm (A7)	4,197,429	1,949,700	2,247,729	115.3	101,710	64,888	36,822	56.7	4.12686	3.00472	1.12214	37.3
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	46,751	206,300	(159,549)	(77.3)	1,528	5,158	(3,630)	(70.4)	3.05962	3.99961	(0.93999)	(23.5)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	716,550	919,600	(203,050)	(22.1)	40,149	39,966	183	0.5	1.78473	2.30096	(0.51623)	(22.4)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	4,960,730	3,075,600	1,885,130	61.3	143,387	110,012	33,375	30.3	3.45968	2.79570	0.66398	23.8
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,571,738	1,673,155	(101,417)	(6.1)				
14. Fuel Cost of Economy Sales (A6)	446,791	1,104,100	(657,309)	(59.5)	31,986	70,187	(38,201)	(54.4)	1.39683	1.57308	(0.17625)	(11.2)
15. Gain on Economy Sales - 80% (A6)	89,952	327,520	(237,568)	(72.5)	31,986 (a)	70,187 (a)	(38,201)	(54.4)	0.28122	0.46664	(0.18542)	(39.7)
16. Fuel Cost of Sch. D Separ. Sales (A6)	429,035	449,200	(20,165)	(4.5)	30,758	30,800	(42)	(0.1)	1.39487	1.45844	(0.06357)	(4.4)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	65,180	64,700	480	0.7	4,542	3,883	659	17.0	1.43505	1.66624	(0.23119)	(13.9)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,936	0	2,936	0.0	75	0	75	0.0	3.91467	0.00000	3.91467	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	166,743	0	166,743	0.0	7,220	0	7,220	0.0	2.30946	0.00000	2.30946	0.0
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	479,465	328,300	151,165	46.0	30,060	14,215	15,845	111.5	1.59503	2.30953	(0.71450)	(30.9)
21. Fuel Cost of Other Power Sales (A6)	0	928,600	(928,600)	(100.0)	0	63,240	(63,240)	(100.0)	0.00000	1.46837	(1.46837)	(100.0)
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	1,680,102	3,202,420	(1,522,318)	(47.5)	104,641	182,325	(77,684)	(42.6)	1.60559	1.75643	(0.15084)	(8.6)
23. Net Inadvertant Interchange					927	0	927	0.0				
24. Wheeling Rec'd. less Wheeling Dely'd.					395	0	395	0.0				
25. Interchange and Wheeling Losses					2,599	2,800	(201)	(7.2)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	31,530,563	33,172,138	(1,641,575)	(4.9)	1,465,820	1,488,030	(22,210)	(1.5)	2.15105	2.22927	(0.07822)	(3.5)
27. Net Unbilled	3,428,817 (a)	2,438,509 (a)	990,308	40.6	159,402	109,386	50,016	45.7	0.23392	0.16387	0.07005	42.7
28. Company Use	83,439 (a)	84,712 (a)	(1,273)	(1.5)	3,879	3,800	79	2.1	0.00680	0.00650	0.00030	4.6
29. T & D Losses	1,608,878 (a)	1,609,600 (a)	(722)	0.0	74,795	72,203	2,592	3.6	0.13104	0.12356	0.00748	6.1
30. System KWH Sales	31,530,563	33,172,138	(1,641,575)	(4.9)	1,227,744	1,302,641	(74,897)	(5.7)	2.56817	2.54653	0.02164	0.8
31. Wholesale KWH Sales	(476,523)	(313,885)	(162,638)	51.8	(18,555)	(12,326)	(6,229)	50.5	2.56816	2.54653	0.02163	0.8
32. Jurisdictional KWH Sales	31,054,040	32,858,253	(1,804,213)	(5.5)	1,209,189	1,290,315	(81,126)	(6.3)	2.56817	2.54653	0.02164	0.8
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	31,058,077	32,862,525	(1,804,448)	(5.5)	1,209,189	1,290,315	(81,126)	(6.3)	2.56850	2.54686	0.02164	0.8
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	420,138	422,549	(2,411)	(0.6)	1,209,189	1,290,315	(81,126)	(6.3)	0.03475	0.03275	0.00200	6.1
36. Fuel Credit Differential - FMPA/Lakeland Sale	0	(514,746)	514,746	(100.0)	1,209,189	1,290,315	(81,126)	(6.3)	0.00000	(0.03989)	0.03989	(100.0)
37. True-up *	(728,854)	(728,854)	0	0.0	1,209,189	1,290,315	(81,126)	(6.3)	(0.06028)	(0.05649)	(0.00379)	6.7
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	30,749,361	32,041,474	(1,292,113)	(4.0)	1,209,189	1,290,315	(81,126)	(6.3)	2.54297	2.48323	0.05974	2.4
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.54508	2.48529	0.05979	2.4
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,209,189	1,290,315	(81,126)	(6.3)	(0.00501)	(0.00470)	(0.00031)	6.6
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	30,688,770	31,980,883	(1,292,113)	(4.0)	1,209,189	1,290,315	(81,126)	(6.3)	2.54007	2.48059	0.05948	2.4
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.540	2.481	0.059	2.4

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MAY, 1998

SCHEDULE A1
REVISED LINE 36 WITH T-UP FILING

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	55,691,627	63,211,493	(7,519,866)	(11.9)	2,758,318	2,964,068	(205,750)	(6.9)	2.01904	2.13259	(0.11355)	(5.3)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,808)	(7,000)	192	(2.7)	2,758,318 (a)	2,964,068 (a)	(205,750)	(6.9)	(0.00025)	(0.00024)	(0.00001)	4.2
4b. Adjustments to Fuel Cost	0	0	0	0.0	2,758,318 (a)	2,964,068 (a)	(205,750)	(6.9)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	2,758,318 (a)	2,964,068 (a)	(205,750)	(6.9)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	55,684,819	63,204,493	(7,519,674)	(11.9)	2,758,318	2,964,068	(205,750)	(6.9)	2.01880	2.13236	(0.11356)	(5.3)
6. Fuel Cost of Purchased Power - Firm (A7)	4,393,207	2,461,500	1,931,707	78.5	120,326	77,218	43,108	55.8	3.65109	3.18773	0.46336	14.5
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	59,979	287,000	(227,021)	(79.1)	1,994	7,026	(5,032)	(71.6)	3.00797	4.08483	(1.07686)	(26.4)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	1,354,875	1,819,200	(464,325)	(25.5)	80,091	78,643	1,448	1.8	1.69167	2.31324	(0.62157)	(26.9)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	5,808,061	4,567,700	1,240,361	27.2	202,411	162,887	39,524	24.3	2.86944	2.80421	0.06523	2.3
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					2,960,729	3,126,955	(166,226)	(5.3)				
14. Fuel Cost of Economy Sales (A6)	1,754,537	2,694,900	(940,363)	(34.9)	126,383	173,359	(46,976)	(27.1)	1.38827	1.55452	(0.16625)	(10.7)
15. Gain on Economy Sales - 80% (A6)	406,534	760,240	(353,706)	(46.5)	126,383	173,359 (a)	(46,976)	(27.1)	0.32167	0.43854	(0.11687)	(26.6)
16. Fuel Cost of Sch. B Separ. Sales (A6)	831,538	873,300	(41,762)	(4.8)	59,565	60,240	(675)	(1.1)	1.39602	1.44970	(0.05368)	(3.7)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	148,512	121,900	26,612	21.8	10,227	7,437	2,790	37.5	1.45216	1.63910	(0.18694)	(11.4)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	2,936	0	2,936	0.0	75	0	75	0.0	3.91467	0.00000	3.91467	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	297,877	129,700	168,177	129.7	12,691	5,400	7,291	135.0	2.34715	2.40185	(0.05470)	(2.3)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	699,309	836,400	(137,091)	(16.4)	39,312	36,446	2,866	7.9	1.77887	2.29490	(0.51603)	(22.5)
21. Fuel Cost of Other Power Sales (A6)	264,157	1,826,200	(1,562,043)	(85.5)	16,664	124,440	(107,776)	(86.6)	1.58520	1.46753	0.11767	8.0
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	4,405,400	7,242,640	(2,837,240)	(39.2)	264,917	407,322	(142,405)	(35.0)	1.66294	1.77811	(0.11517)	(6.5)
23. Net Inadvertant Interchange					1,522	0	1,522	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,011	0	1,011	0.0				
25. Interchange and Wheeling Losses					5,864	6,200	(336)	(5.4)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	57,087,480	60,529,553	(3,442,073)	(5.7)	2,692,481	2,713,433	(20,952)	(0.8)	2.12026	2.23074	(0.11048)	(5.0)
27. Net Unbilled	3,311,804 (a)	2,484,308 (a)	827,496	33.3	156,198	111,367	44,831	40.3	0.12300	0.09156	0.03144	34.3
28. Company Use	158,002 (a)	169,536 (a)	(11,534)	(6.8)	7,452	7,600	(148)	(1.9)	0.00657	0.00688	(0.00031)	(4.5)
29. T & D Losses	2,633,554 (a)	2,942,480 (a)	(308,926)	(10.5)	124,209	131,906	(7,697)	(5.8)	0.10952	0.11949	(0.00997)	(8.3)
30. System KWH Sales	57,087,480	60,529,553	(3,442,073)	(5.7)	2,404,622	2,462,560	(57,938)	(2.4)	2.37407	2.45799	(0.08392)	(3.4)
31. Wholesale KWH Sales	(710,750)	(393,629)	(317,121)	80.6	(29,341)	(15,707)	(13,634)	86.8	2.42238	2.50607	(0.08369)	(3.3)
32. Jurisdictional KWH Sales	56,376,730	60,135,924	(3,759,194)	(6.3)	2,375,281	2,446,853	(71,572)	(2.9)	2.37348	2.45768	(0.08420)	(3.4)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	56,384,059	60,143,742	(3,759,683)	(6.3)	2,375,281	2,446,853	(71,572)	(2.9)	2.37378	2.45800	(0.08422)	(3.4)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	842,349	850,414	(8,065)	(0.9)	2,375,281	2,446,853	(71,572)	(2.9)	0.03546	0.03476	0.00070	2.0
36. Fuel Credit Differential - FMPA/Lakeland Sale	(13,179)	(1,032,480)	1,019,301	(98.7)	2,375,281	2,446,853	(71,572)	(2.9)	(0.00055)	(0.04220)	0.04165	(98.7)
37. True-up *	(1,457,708)	(1,457,708)	0	0.0	2,375,281	2,446,853	(71,572)	(2.9)	(0.06137)	(0.05957)	(0.00180)	3.0
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	55,755,521	58,503,968	(2,748,447)	(4.7)	2,375,281	2,446,853	(71,572)	(2.9)	2.34732	2.39099	(0.04367)	(1.8)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.34927	2.39297	(0.04370)	(1.8)
41. GPIF * (Already Adjusted for Taxes)	(121,182)	(121,182)	0	0.0	2,375,281	2,446,853	(71,572)	(2.9)	(0.00510)	(0.00495)	(0.00015)	3.0
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	55,634,339	58,382,786	(2,748,447)	(4.7)	2,375,281	2,446,853	(71,572)	(2.9)	2.34417	2.38802	(0.04385)	(1.8)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.344	2.388	(0.044)	(1.8)

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

SCHEDULE A2
PAGE 1 OF 3

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	28,253,753	33,302,458	(5,048,705)	(15.2)	55,691,627	63,211,493	(7,519,866)	(11.9)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	1,680,102	3,202,420	(1,522,318)	(47.5)	4,405,400	7,242,640	(2,837,240)	(39.2)
3. FUEL COST OF PURCHASED POWER	4,197,429	1,949,700	2,247,729	115.3	4,393,207	2,461,500	1,931,707	78.5
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	716,550	919,600	(203,050)	(22.1)	1,354,875	1,819,200	(464,325)	(25.5)
4. ENERGY COST OF ECONOMY PURCHASES	46,751	206,300	(159,549)	(77.3)	59,979	287,000	(227,021)	(79.1)
5. TOTAL FUEL & NET POWER TRANSACTION	31,534,381	33,175,638	(1,641,257)	(4.9)	57,094,288	60,536,553	(3,442,265)	(5.7)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,818)	(3,500)	(318)	9.1	(6,808)	(7,000)	192	(2.7)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	31,530,563	33,172,138	(1,641,575)	(4.9)	57,087,480	60,529,553	(3,442,073)	(5.7)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,209,189	1,290,315	(81,126)	(6.3)	2,375,281	2,446,853	(71,572)	(2.9)
2. NONJURISDICTIONAL SALES	18,555	12,326	6,229	50.5	29,341	15,707	13,634	86.8
3. TOTAL SALES	1,227,744	1,302,641	(74,897)	(5.7)	2,404,622	2,462,560	(57,938)	(2.4)
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9848869	0.9905377	(0.0056508)	(0.6)	0.9877981	0.9936217	(0.0058236)	(0.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

C. TRUE-UP CALCULATION	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
1. JURISDICTIONAL FUEL REVENUE	27,856,841	30,139,984	(2,283,143)	(7.6)	54,833,315	57,136,577	(2,303,262)	(4.0)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,854	728,854	0	0.0	1,457,708	1,457,708	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	121,182	121,182	0	0.0
c. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	28,646,286	30,929,429	(2,283,143)	(7.4)	56,412,205	58,715,467	(2,303,262)	(3.9)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	31,530,563	33,172,138	(1,641,575)	(4.9)	57,087,480	60,529,553	(3,442,073)	(5.7)
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9848869	0.9905377	(0.0056508)	(0.6)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	31,054,040	32,858,253	(1,804,213)	(5.5)	56,376,730	60,135,924	(3,759,194)	(6.3)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	31,058,077	32,862,525	(1,804,448)	(5.5)	56,384,059	60,143,742	(3,759,683)	(6.3)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	426,585	426,585	0	0.0	852,701	855,701	(3,000)	(0.4)
6D.(LINE 6C x LINE 5)	420,138	422,549	(2,411)	(0.6)	842,349	850,414	(8,065)	(0.9)
6E.FUEL CREDIT DIFFERENTIAL - FMPA/LKL SALE	0	(514,746)	514,746	0.0	(13,179)	(1,032,480)	1,019,301	(98.7)
6F. JURISDIC. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND ADJUSTMENT	31,478,215	32,770,328	(1,292,113)	(3.9)	57,213,229	59,961,676	(2,748,447)	(4.6)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6F)	(2,831,929)	(1,840,899)	(991,030)	53.8	(801,024)	(1,246,209)	445,185	(35.7)
8. INTEREST PROVISION FOR THE MONTH	18,270	14,878	3,392	22.8	41,728	36,408	5,320	14.6
9. TRUE-UP & INT. PROV. BEG. OF MONTH	11,794,451	10,302,894	1,491,557	14.5	NOT APPLICABLE			
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,854)	(728,854)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	2,209,531	1,705,612	503,919	29.5	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	5,752,044	4,260,487	1,491,557	35.0	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	2,191,261	1,690,734	500,527	29.6	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	7,943,305	5,951,221	1,992,084	33.5	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	3,971,653	2,975,611	996,042	33.5	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.530	6.000	(0.470)	(7.8)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.500	6.000	(0.500)	(8.3)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.030	12.000	(0.970)	(8.1)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.515	6.000	(0.485)	(8.1)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.460	0.500	(0.040)	(8.0)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	18,270	14,878	3,392	22.8	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	978,508	708,646	269,862	38.1	1,188,298	1,218,172	(29,874)	(2.5)
2	LIGHT OIL	625,768	837,740	(211,972)	(25.3)	1,426,850	1,613,195	(186,345)	(11.6)
3	COAL	26,649,477	31,756,072	(5,106,595)	(16.1)	53,076,479	60,380,126	(7,303,647)	(12.1)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	28,253,753	33,302,458	(5,048,705)	(15.2)	55,691,627	63,211,493	(7,519,866)	(11.9)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	26,877	16,103	10,774	66.9	32,618	27,379	5,239	19.1
9	LIGHT OIL	12,231	18,407	(6,176)	(33.6)	37,986	35,608	2,378	6.7
10	COAL	1,389,243	1,528,633	(139,390)	(9.1)	2,687,714	2,901,081	(213,367)	(7.4)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,428,351	1,563,143	(134,792)	(8.6)	2,758,318	2,964,068	(205,750)	(6.9)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	57,481	36,869	20,612	55.9	68,608	63,011	5,597	8.9
16	LIGHT OIL (BBL)	29,642	30,396	(754)	(2.5)	67,706	58,135	9,571	16.5
17	COAL (TON)	656,696	688,067	(31,371)	(4.6)	1,275,708	1,299,845	(24,137)	(1.9)
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	362,757	233,051	129,706	55.7	432,782	398,298	34,484	8.7
22	LIGHT OIL	172,063	176,201	(4,138)	(2.3)	388,194	337,106	51,088	15.2
23	COAL	14,497,627	15,564,783	(1,067,156)	(6.9)	28,322,953	29,583,066	(1,260,113)	(4.3)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	15,032,447	15,974,035	(941,588)	(5.9)	29,143,929	30,318,470	(1,174,541)	(3.9)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	1.88	1.03	0.85	-	1.18	0.92	0.26	-
29	LIGHT OIL	0.86	1.18	(0.32)	-	1.38	1.20	0.18	-
30	COAL	97.26	97.79	(0.53)	-	97.44	97.88	(0.44)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	17.02	19.22	(2.20)	(11.4)	17.32	19.33	(2.01)	(10.4)
36	LIGHT OIL ($/BBL)	21.11	27.56	(6.45)	(23.4)	21.07	27.75	(6.68)	(24.1)
37	COAL ($/TON)	40.58	46.15	(5.57)	(12.1)	41.61	46.45	(4.84)	(10.4)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	2.70	3.04	(0.34)	(11.2)	2.75	3.06	(0.31)	(10.1)
42	LIGHT OIL	3.64	4.75	(1.11)	(23.4)	3.68	4.79	(1.11)	(23.2)
43	COAL	1.84	2.04	(0.20)	(9.8)	1.87	2.04	(0.17)	(8.3)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.88	2.08	(0.20)	(9.6)	1.91	2.08	(0.17)	(8.2)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: MAY, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	13,497	14,473	(976)	(6.7)	13,268	14,548	(1,280)	(8.8)
49	LIGHT OIL	14,068	9,572	4,496	47.0	10,219	9,467	752	7.9
50	COAL	10,436	10,182	254	2.5	10,538	10,197	341	3.3
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,524	10,219	305	3.0	10,566	10,229	337	3.3
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.64	4.40	(0.76)	(17.3)	3.64	4.45	(0.81)	(18.2)
56	LIGHT OIL	5.12	4.55	0.57	12.5	3.76	4.53	(0.77)	(17.0)
57	COAL	1.92	2.08	(0.16)	(7.7)	1.97	2.08	(0.11)	(5.3)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	1.98	2.13	(0.15)	(7.0)	2.02	2.13	(0.11)	(5.2)

SCHEDULE A4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: MAY, 1998

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPAB-ILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	3958	16.6	100.0	36.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	3251	13.7	100.0	33.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	4599	19.3	100.0	39.5	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	6200	20.3	99.6	46.4	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	0	0.0	0.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	18008	11.9	67.1	26.5	15624	HVY.OIL	44506	6321750	281355.8	713396	3.96	16.03
GAN.#1	114	55541	65.5	79.2	71.5	11380	COAL	32565	19408681	632043.7	1275107	2.30	39.16
GAN.#2	108	44925	55.9	73.3	69.4	12730	COAL	28623	19980138	571891.5	1120755	2.49	39.16
GAN.#3	155	74744	64.8	84.2	71.5	11607	COAL	45359	19125841	867529.0	1776066	2.38	39.16
GAN.#4	169	77877	61.9	78.4	75.4	11569	COAL	47267	19061341	900972.4	1850775	2.38	39.16
GAN.#5	227	129708	76.8	86.6	83.8	10338	COAL	55423	24194340	1340922.9	2170129	1.67	39.16
GAN.#6	362	192827	71.6	80.8	83.1	10167	COAL	83133	23582920	1960518.9	3255135	1.69	39.16
GANNON STA.	1135	575622	68.2	81.2	78.0	10899	COAL	292370	21458694	6273878.4	11447967	1.99	39.16
B.B.#1	421	221212	70.6	82.0	83.1	9965	COAL	96365	22874580	2204308.9	3852491	1.74	39.98
B.B.#2	416	165768	53.6	62.3	76.4	9887	COAL	72927	22473500	1638924.9	2915484	1.76	39.98
B.B.#3	428	110815	34.8	39.4	79.3	10053	COAL	48379	23026619	1114004.8	1934101	1.75	39.98
B.B. 1 - 3	1265	497795	52.9	61.1	79.6	9958	COAL	217671	22773997	4957238.6	8702076	1.75	39.98
B.B.#4	442	296647	90.2	97.1	90.2	9986	COAL	134553	22015250	2962218.0	5875652	1.98	43.67
B.B. STA.	1707	794442	62.6	70.4	82.4	9969	COAL	352224	22484148	7919456.6	14577728	1.83	41.39
SEB-PHIL. #1(HVY OIL)	17	4537	35.9	99.9	83.9	9178	HVY.OIL	6638	6273200	41641.5	135631	2.99	20.43
SEB-PHIL. #2(HVY OIL)	17	4332	34.3	98.0	85.5	9178	HVY.OIL	6337	6274152	39759.3	129481	2.99	20.43
SEB-PHILLIPS TOTAL	34	8869	35.1	99.0	84.7	9178	HVY.OIL	12975	6273665	81400.8	265112	2.99	20.43
POLK COAL	250	19179	10.3	14.7	70.4	15866	COAL	12102	25144001	304292.7	623782	3.25	51.54
POLK OIL	225	3941	2.4	15.8	42.2	10369	LGT.OIL	7037	5806878	40863.0	146256	3.71	20.78
POLK TOTAL	250	23120	12.7	30.5	-	14929	-	-	-	345155.7	770038	3.33	-
GAN.C.T.#1	15	710	6.4	100.0	69.6	18359	LGT.OIL	2240	5819196	13035.0	47519	6.69	21.21
B.B.C.T.#1	15	506	4.5	100.0	68.8	18844	LGT.OIL	1643	5803348	9534.9	34852	6.89	21.21
B.B.C.T.#2	65	5592	11.6	100.0	69.9	14953	LGT.OIL	14411	5802248	83616.2	305694	5.47	21.21
B.B.C.T.#3	65	1482	3.1	100.0	57.0	16879	LGT.OIL	4311	5802366	25014.0	91447	6.17	21.21
C.T. TOTAL	160	8290	7.0	100.0	18.5	15826	LGT.OIL	22605	5804030	131200.1	479512	5.78	21.21
TOT. COAL (GN,BB,POLK)	3092	1389243	60.4	69.9	79.8	10436	COAL	656696	22076619	14497627.7	26649477	1.92	40.58
SYSTEM	3490	1428351	55.0	71.4	76.0	10524	-	-	-	15032447.4	28253753	1.98	-

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
SEB-PHIL. = SEBRING-PHILLIPS
GAN. = GANNON
C.T. = COMBUSTION TURBINE

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)								
1	PURCHASES:								
2	UNITS (BBL)	4,807	36,869	(32,062)	(87.0)	5,290	63,011	(57,721)	(91.6)
3	UNIT COST ($/BBL)	17.37	17.87	(0.50)	(2.8)	(27.61)	17.80	(45.41)	(255.1)
4	AMOUNT ($)	83,487	658,872	(575,385)	(87.3)	(146,040)	1,121,885	(1,267,925)	(113.0)
5	BURNED:								
6	UNITS (BBL)	57,481	36,869	20,612	55.9	68,608	63,011	5,597	8.9
7	UNIT COST ($/BBL)	17.02	19.22	(2.20)	(11.4)	17.32	19.33	(2.01)	(10.4)
8	AMOUNT ($)	978,508	708,646	269,862	38.1	1,188,298	1,218,172	(29,874)	(2.5)
9	ENDING INVENTORY:								
10	UNITS (BBL)	127,276	139,530	(12,254)	(8.8)	127,276	139,530	(12,254)	(8.8)
11	UNIT COST ($/BBL)	16.28	17.89	(1.61)	(9.0)	16.28	17.89	(1.61)	(9.0)
12	AMOUNT ($)	2,072,018	2,496,590	(424,572)	(17.0)	2,072,018	2,496,590	(424,572)	(17.0)
13									
14	DAYS SUPPLY:	115	126	(11)	(8.7)	-	-	-	-
	LIGHT OIL (2)								
15	PURCHASES:								
16	UNITS (BBL)	34,464	41,611	(7,147)	(17.2)	76,770	80,243	(3,473)	(4.3)
17	UNIT COST ($/BBL)	20.34	27.24	(6.90)	(25.3)	18.71	27.59	(8.88)	(32.2)
18	AMOUNT ($)	701,105	1,133,548	(432,443)	(38.1)	1,436,138	2,213,557	(777,419)	(35.1)
19	BURNED:								
20	UNITS (BBL)	29,642	30,396	(754)	(2.5)	67,706	58,135	9,571	16.5
21	UNIT COST ($/BBL)	21.11	27.56	(6.45)	(23.4)	21.07	27.75	(6.68)	(24.1)
22	AMOUNT ($)	625,768	837,740	(211,972)	(25.3)	1,426,850	1,613,195	(186,345)	(11.6)
23	ENDING INVENTORY:								
24	UNITS (BBL)	76,883	60,844	16,039	26.4	76,883	60,844	16,039	26.4
25	UNIT COST ($/BBL)	21.00	27.72	(6.72)	(24.2)	21.00	27.72	(6.72)	(24.2)
26	AMOUNT ($)	1,614,861	1,686,300	(71,439)	(4.2)	1,614,861	1,686,300	(71,439)	(4.2)
27									
28	DAYS SUPPLY: NORMAL	64	51	13	25.5	-	-	-	-
29	DAYS SUPPLY: EMERGENCY	11	9	2	22.2	-	-	-	-
	COAL (3)								
30	PURCHASES:								
31	UNITS (TONS)	972,293	738,500	233,793	31.7	1,547,495	1,451,000	96,495	6.7
32	UNIT COST ($/TON)	39.39	45.81	(6.42)	(14.0)	40.28	45.67	(5.39)	(11.8)
33	AMOUNT ($)	38,294,764	33,829,854	4,464,910	13.2	62,327,727	66,271,922	(3,944,195)	(6.0)
34	BURNED:								
35	UNITS (TONS)	656,696	688,067	(31,371)	(4.6)	1,275,708	1,299,845	(24,137)	(1.9)
36	UNIT COST ($/TON)	40.58	46.15	(5.57)	(12.1)	41.61	46.45	(4.84)	(10.4)
37	AMOUNT ($)	26,649,477	31,756,072	(5,106,595)	(16.1)	53,076,479	60,380,126	(7,303,647)	(12.1)
38	ENDING INVENTORY:								
39	UNITS (TONS)	904,116	679,504	224,612	33.1	904,116	679,504	224,612	33.1
40	UNIT COST ($/TON)	39.98	46.00	(6.02)	(13.1)	39.98	46.00	(6.02)	(13.1)
41	AMOUNT ($)	36,150,401	31,255,107	4,895,294	15.7	36,150,401	31,255,107	4,895,294	15.7
42									
43	DAYS SUPPLY:	37	28	9	32.1	-	-	-	-
	NATURAL GAS								
44	PURCHASES:								
45	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
48	BURNED:								
49	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:								
53	UNITS (MCF)	0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
56									
57	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-
	NUCLEAR								
58	BURNED:								
59	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY, 1998

	OTHER		CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
62	PURCHASES:									
63	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:									
67	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:									
71	UNITS	(MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST	($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT	($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS *DUE TO:*

	DOLLARS
IGNITION	12,568
FUEL ANALYSIS	224
TOTAL	12,792

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(9,585)	(203,888)
OTHER USAGE	(1,760)	(37,138)
TOTAL	(11,345)	(241,026)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	191,320
FUEL ANALYSIS	27,921
AERIAL SURVEY ADJ.	(72,543)
ADDITIVES	60,565
PROPANE IGNITION	7,209
TOTAL	214,472

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF MAY, 1998

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) ---cents/KWH--- (A) FUEL COST	(6) (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	70,187.0	0.0	70,187.0	1.700	2.283	1,193,200.00	1,602,600.00	327,520.00
VARIOUS	JURISDICTIONAL	SCH. -D	3,883.0	0.0	3,883.0	1.666	1.666	64,700.00	64,700.00	
VARIOUS	SEPARATED	SCH. -D	30,800.0	0.0	30,800.0	1.458	1.710	449,200.00	526,800.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	14,215.0	0.0	14,215.0	2.310	3.118	328,300.00	443,200.00	
LAKELAND/FMPA		SCH. -D	63,240.0	0.0	63,240.0	1.468	1.563	928,600.00	988,400.00	
VARIOUS	JURISDICTIONAL	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	182,325.0	0.0	182,325.0	1.626	1.989	2,964,000.00	3,625,700.00	327,520.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(89,100.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						327,520.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	182,325.0	0.0	182,325.0	1.756	1.989	3,202,420.00	3,625,700.00	327,520.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	896.0	0.0	896.0	1.598	2.135	14,320.62	19,128.90	3,846.62
FLA. PWR. & LIGHT		ECON.-C	9,858.0	0.0	9,858.0	1.552	1.759	152,993.58	173,394.10	16,320.42
CITY OF LAKELAND		ECON.-C	229.0	0.0	229.0	1.605	1.945	3,676.07	4,455.05	623.18
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	5.0	0.0	5.0	1.674	2.301	83.70	115.05	25.08
CITY OF HOMESTEAD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	96.0	0.0	96.0	1.535	2.202	1,473.80	2,114.05	512.20
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	6,644.0	0.0	6,644.0	1.572	1.897	104,462.78	126,007.28	17,235.60
SEMINOLE ELECTRIC CO-OP		ECON.-C	1,079.0	0.0	1,079.0	1.568	2.253	16,919.53	24,312.42	5,914.31
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	225.0	0.0	225.0	1.560	1.812	3,510.63	4,076.49	452.69
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	12,763.0	0.0	12,763.0	1.558	1.996	198,881.90	254,711.07	44,663.34
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	8,502.0	0.0	8,502.0	1.699	1.843	144,444.66	156,666.51	
REEDY CREEK	SEPAR.	SCH. -D	14,880.0	0.0	14,880.0	1.352	1.622	201,177.60	241,353.60	
WAUCHULA	SEPAR.	SCH. -D	3,720.0	0.0	3,720.0	1.352	1.622	50,294.40	60,338.40	
FT. MEADE	SEPAR.	SCH. -D	3,656.0	0.0	3,656.0	1.352	1.622	49,429.12	59,300.32	
ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	30,060.0	0.0	30,060.0	1.760	2.418	529,056.00	726,850.80	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	4,600.0	834.1	3,765.9	1.347	1.347	50,723.56	50,723.56	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	776.0	0.0	776.0	1.863	1.863	14,456.12	14,456.12	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	7,220.0	0.0	7,220.0	2.309	2.309	166,743.22	166,743.22	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA		SCH. -D	63,240.0	63,240.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF MAY, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
HARDEE PWR. PARTNERS TO FPC	ECON.-C	105.0	0.0	105.0	1.881	2.058	1,975.05	2,161.25	148.96 *
HARDEE PWR. PARTNERS TO FP&L	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO REEDY CREEK	ECON.-C	45.0	0.0	45.0	1.881	2.133	846.45	959.96	90.81 *
HARDEE PWR. PARTNERS TO GAINESVILLE	ECON.-C	41.0	0.0	41.0	1.881	2.243	771.21	919.68	118.78 *
HARDEE PWR. PARTNERS TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO NEW SMYRNA BCH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO ORLANDO	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE PWR. PARTNERS TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKE WORTH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE	SCH. -G	75.0	0.0	75.0	3.915	3.915	2,935.88	2,935.88	
ADJUSTMENTS TO APRIL 1998									
HARDEE POWER PARTNERS SEPAR.	CONTRACT	(9,252.0)	0.0	(9,252.0)	2.296	2.969	(212,425.92)	(274,691.88)	
HARDEE POWER PARTNERS SEPAR.	CONTRACT	9,252.0	0.0	9,252.0	1.760	2.418	162,835.20	223,713.36	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	(7,723.0)	0.0	(7,723.0)	1.723	1.867	(133,104.63)	(144,188.24)	
CITY OF NEW SMYRNA BCH. SEPAR.	SCH. -D	7,723.0	0.0	7,723.0	1.723	1.863	133,104.63	143,914.72	
SUB-TOTAL ECONOMY POWER SALES		31,986.0	0.0	31,986.0	1.563	1.914	499,915.32	612,355.30	89,951.99
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		30,758.0	0.0	30,758.0	1.448	1.682	445,345.78	517,385.31	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		5,376.0	834.1	4,541.9	1.435	1.435	65,179.68	65,179.68	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		7,220.0	0.0	7,220.0	2.309	2.309	166,743.22	166,743.22	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		30,060.0	0.0	30,060.0	1.595	2.248	479,465.28	675,872.28	
SUB-TOTAL OTHER SCHEDULE D POWER SALES		63,240.0	63,240.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE G POWER SALES		75.0	0.0	75.0	3.915	3.915	2,935.88	2,935.88	
TOTAL INCLUDING VARIABLE O & M COSTS	-	168,715.0	64,074.1	104,640.9	1.586	1.950	1,659,585.16	2,040,471.67	89,951.99
LESS VARIABLE O & M COSTS	-						(53,097.65)		
LESS VARIABLE O & M COSTS - HARDEE	-						(26.74)		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(16,310.92)		
PLUS 80% OF ECON. ENERGY SALES PROFITS	-						89,951.99		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS	-	168,715.0	64,074.1	104,640.9	1.606	1.950	1,680,101.84	2,040,471.67	89,951.99
CURRENT MONTH:									
DIFFERENCE	-	(13,610.0)	64,074.1	(77,684.1)	(0.150)	(0.039)	(1,522,318.16)	(1,585,228.33)	(237,568.01)
DIFFERENCE %	-	(7.5)	0.0	(42.6)	(8.5)	(2.0)	(47.5)	(43.7)	(72.5)
PERIOD TO DATE:									
ACTUAL	-	373,452.0	108,535.5	264,916.5	1.663	1.954	4,405,399.92	5,175,784.89	406,534.31
ESTIMATED	-	407,322.0	0.0	407,322.0	1.778	2.017	7,242,640.00	8,216,700.00	760,240.00
DIFFERENCE	-	(33,870.0)	108,535.5	(142,405.5)	(0.115)	(0.063)	(2,837,240.08)	(3,040,915.11)	(353,705.69)
DIFFERENCE %	-	(8.3)	0.0	(35.0)	(6.5)	(3.1)	(39.2)	(37.0)	(46.5)

* THE PROFITS REFLECTED ARE ONLY ON TEC 40%. SEC 60% OR $778.06 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF MAY, 1998

SCHEDULE A7

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	3,778.0	0.0	2,515.0	1,263.0	5.162	5.162	65,200.00
HARDEE POWER PARTNERS	IPP	63,625.0	0.0	0.0	63,625.0	2.962	2.962	1,884,500.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	67,403.0	0.0	2,515.0	64,888.0	3.005	3.005	1,949,700.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	53,528.0	0.0	0.0	53,528.0	2.979	2.979	1,594,796.89
HARDEE PWR. PART.-OTHERS	IPP	266.0	0.0	0.0	266.0	2.214	2.234	5,888.84
FLA. POWER CORP.	SCH.-Ja	13,003.0	0.0	11,824.6	1,178.4	6.933	6.933	81,697.72
FLA. POWER CORP.	SCH.-Jc	10,493.0	0.0	0.0	10,493.0	3.567	3.567	374,293.15
FLA. POWER & LIGHT	SCH.-Ja	18,883.0	0.0	11,609.5	7,273.5	5.498	5.498	399,907.84
FLA. POWER & LIGHT	SCH.-Jc	10,951.0	0.0	0.0	10,951.0	3.388	3.388	371,033.06
CITY OF LAKELAND	SCH.-Ja	433.0	0.0	433.0	0.0	0.000	ERR	0.00
CITY OF LAKELAND	SCH.-Jc	1,306.0	0.0	0.0	1,306.0	3.120	3.120	40,745.00
ORLANDO UTIL. COMM.	SCH.-Ja	7,073.0	0.0	2,964.5	4,108.5	6.587	6.587	270,632.70
ORLANDO UTIL. COMM.	SCH.-Jc	7,935.0	0.0	0.0	7,935.0	3.517	3.517	279,085.10
SEMINOLE ELECTRIC CO-OP	SCH.-Ja	449.0	0.0	449.0	0.0	0.000	ERR	0.00
THE ENERGY AUTHORITY	SCH.-Ja	667.0	0.0	8.0	659.0	6.433	6.433	42,395.00
THE ENERGY AUTHORITY	SCH.-Jc	669.0	0.0	0.0	669.0	4.373	4.373	29,253.45
CITY OF GAINESVILLE	SCH.-Ja	2,896.0	0.0	1,486.6	1,409.4	4.799	4.799	67,636.24
CITY OF GAINESVILLE	SCH.-Jc	897.0	0.0	0.0	897.0	4.713	4.713	42,274.34
PECO	SCH.-Ja	203.0	0.0	43.0	160.0	4.500	4.500	7,200.00
PECO	SCH.-Jc	117.0	0.0	0.0	117.0	4.500	4.500	5,265.00
KOCK ENERGY TRAD.	SCH.-Ja	1,145.0	0.0	386.0	759.0	8.922	8.922	67,720.24
PECO	OTHER	39,215.0	39,215.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS:								
HARDEE PWR.PART.-NATIVE 4/98	IPP	(4,081.0)	0.0	0.0	(4,081.0)	(7.372)	(7.372)	300,850.58
HARDEE PWR.PART.-NATIVE 4/98	IPP	4,081.0	0.0	0.0	4,081.0	5.311	5.311	216,754.10
TOTAL		194,154.0	63,240.0	29,204.2	101,709.8	4.127	4.127	4,197,429.25
CURRENT MONTH:								
DIFFERENCE	-	126,751.0	63,240.0	26,689.2	36,821.8	1.122	1.122	2,247,729.25
DIFFERENCE %	-	188.0	0.0	1,061.2	56.7	37.3	37.3	115.3
PERIOD TO DATE:								
ACTUAL	-	257,639.0	107,691.0	29,622.1	120,325.9	3.651	3.651	4,393,207.18
ESTIMATED	-	81,769.0	0.0	4,551.0	77,218.0	3.188	3.188	2,461,500.00
DIFFERENCE	-	175,870.0	107,691.0	25,071.1	43,107.9	0.463	0.463	1,931,707.18
DIFFERENCE %	-	215.1	0.0	550.9	55.8	14.5	14.5	78.5

SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF MAY, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	39,966.0	0.0	0.0	39,966.0	2.301	2.301	919,600.00
TOTAL	-	39,966.0	0.0	0.0	39,966.0	2.301	2.301	919,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	796.0	0.0	0.0	796.0	2.489	2.489	19,815.65
McKAY BAY REFUSE	COGEN.	10,163.0	0.0	0.0	10,163.0	1.772	1.772	180,041.69
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	65.0	0.0	0.0	65.0	2.392	2.392	1,554.76
HILLSBOROUGH COUNTY	COGEN.	19,634.0	0.0	0.0	19,634.0	1.777	1.777	348,827.38
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	419.0	0.0	0.0	419.0	2.327	2.327	9,748.50
FARMLAND HYDRO LP	COGEN.	50.0	0.0	0.0	50.0	4.175	4.175	2,087.34
IMC-AGRICO-S. PIERCE	COGEN.	1,430.0	0.0	0.0	1,430.0	2.342	2.342	33,496.22
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	7,843.0	0.0	0.0	7,843.0	1.816	1.816	142,427.12
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	251.0	(251.0)	5.208	5.208	(13,073.24)
SUB-TOTAL FOR MAY, 1998	-	40,400.0	0.0	251.0	40,149.0	1.806	1.806	724,925.42
ADJUSTMENTS FOR MAR., 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(10,679.0)	0.0	0.0	(10,679.0)	1.565	1.565	(167,178.90)
		10,679.0	0.0	0.0	10,679.0	1.532	1.532	163,588.03
MULBERRY PHOSPHATES INC.	COGEN.							
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(14,874.0)	0.0	0.0	(14,874.0)	1.555	1.555	(231,306.62)
		14,874.0	0.0	0.0	14,874.0	1.525	1.525	226,802.63
CARGILL MILLPOINT	COGEN.							
CF INDUSTRIES INC.	COGEN.							
FARMLAND INDUSTRIES	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(5,647.0)	0.0	0.0	(5,647.0)	1.567	1.567	(88,465.77)
		5,647.0	0.0	0.0	5,647.0	1.562	1.562	88,184.90
AS AVAILABLE ASSIGNMENT	COGEN.							
SUB-TOTAL FOR MAR., 1998 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(8,375.73)
GRAND TOTAL		40,400.0	0.0	251.0	40,149.0	1.785	1.785	716,549.69
CURRENT MONTH:								
DIFFERENCE	-	434.0	0.0	251.0	183.0	(0.516)	(0.516)	(203,050.31)
DIFFERENCE %	-	1.1	0.0	0.0	0.5	(22.4)	(22.4)	(22.1)
PERIOD TO DATE:								
ACTUAL		80,348.0	0.0	257.0	80,091.0	1.692	1.692	1,354,874.42
ESTIMATED		78,643.0	0.0	0.0	78,643.0	2.313	2.313	1,819,200.00
DIFFERENCE	-	1,705.0	0.0	257.0	1,448.0	(0.621)	(0.621)	(464,325.58)
DIFFERENCE %	-	2.2	0.0	0.0	1.8	(26.8)	(26.8)	(25.5)

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF MAY, 1998

SCHEDULE A9

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	5,158.0	4.000	206,300.00	5.052	260,600.00	54,300.00
TOTAL	-	5,158.0	4.000	206,300.00	5.052	260,600.00	54,300.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	122.0	2.593	3,163.95	3.175	3,872.90	708.95
FLA. PWR. & LIGHT	ECON.-C	488.0	3.110	15,174.37	3.172	15,479.75	305.38
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE UTIL. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	70.0	3.682	2,577.44	4.839	3,387.06	809.62
CITY OF HOMESTEAD	ECON.-C	10.0	4.527	452.74	4.715	471.50	18.76
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	67.0	3.497	2,343.27	3.910	2,619.79	276.52
ORLANDO UTIL. COMM.	ECON.-C	748.0	2.982	22,308.73	3.540	26,476.58	4,167.85
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	23.0	3.110	715.39	3.540	814.28	98.89
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ADJUSTMENT TO APR. 1998							
FLA. PWR. & LIGHT	ECON.-C	(278.0)	2.949	(8,197.48)	2.946	(8,189.78)	7.70
FLA. PWR. & LIGHT	ECON.-C	278.0	2.949	8,197.14	2.946	8,189.78	(7.36)
CITY OF GAINESVILLE	ECON.-C	(34.0)	2.623	(891.98)	3.336	(1,134.36)	(242.38)
CITY OF GAINESVILLE	ECON.-C	34.0	2.669	907.38	3.336	1,134.36	226.98
TOTAL	-	1,528.0	3.060	46,750.95	3.477	53,121.86	6,370.91
CURRENT MONTH:							
DIFFERENCE	-	(3,630.0)	(0.940)	(159,549.05)	(1.575)	(207,478.14)	(47,929.09)
DIFFERENCE %	-	(70.4)	(23.5)	(77.3)	(31.2)	(79.6)	(88.3)
PERIOD TO DATE:							
ACTUAL		1,994.0	3.008	59,979.12	3.361	67,017.77	7,038.65
ESTIMATED		7,026.0	4.085	287,000.00	5.102	358,500.00	71,500.00
DIFFERENCE	-	(5,032.0)	(1.077)	(227,020.88)	(1.741)	(291,482.23)	(64,461.35)
DIFFERENCE %	-	(71.6)	(26.4)	(79.1)	(34.1)	(81.3)	(90.2)

COMMISSION SCHEDULES A1 - A9

APRIL 1998

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

SCHEDULE A1

	$				MWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	27,437,874	29,909,035	(2,471,161)	(8.3)	1,329,967	1,400,925	(70,958)	(5.1)	2.06305	2.13495	(0.07190)	(3.4)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,990)	(3,500)	510	(14.6)	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	(0.00022)	(0.00025)	0.00003	(12.0)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	27,434,884	29,905,535	(2,470,651)	(8.3)	1,329,967	1,400,925	(70,958)	(5.1)	2.06282	2.13470	(0.07188)	(3.4)
6. Fuel Cost of Purchased Power - Firm (A7)	195,778	511,800	(316,022)	(61.7)	18,616	12,330	6,286	51.0	1.05167	4.15085	(3.09918)	(74.7)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (A9)	13,228	80,700	(67,472)	(83.6)	466	1,868	(1,402)	(75.1)	2.83863	4.32013	(1.48150)	(34.3)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. X Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. X Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	638,325	899,600	(261,275)	(29.0)	39,942	38,677	1,265	3.3	1.59813	2.32593	(0.72780)	(31.3)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	847,331	1,492,100	(644,769)	(43.2)	59,024	52,875	6,149	11.6	1.43557	2.82194	(1.38637)	(49.1)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,388,991	1,453,800	(64,809)	(4.5)				
14. Fuel Cost of Economy Sales (A6)	1,307,746	1,590,800	(283,054)	(17.8)	94,397	103,172	(8,775)	(8.5)	1.38537	1.54189	(0.15652)	(10.2)
15. Gain on Economy Sales - 80% (A6)	316,582	432,720	(116,138)	(26.8)	94,397 (a)	103,172 (a)	(8,775)	(8.5)	0.33531	0.41942	(0.08405)	(20.0)
16. Fuel Cost of Sch. D Separ. Sales (A6)	402,503	424,100	(21,597)	(5.1)	28,807	29,440	(633)	(2.2)	1.39724	1.44056	(0.04332)	(3.0)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	83,332	57,200	26,132	45.7	5,685	3,554	2,131	60.0	1.46582	1.60945	(0.14363)	(8.9)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	131,134	129,700	1,434	1.1	5,471	5,400	71	1.3	2.39689	2.40185	(0.00496)	(0.2)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	219,844	508,100	(288,256)	(56.7)	9,252	22,231	(12,979)	(58.4)	2.37618	2.28555	0.09063	4.0
21. Fuel Cost of Other Power Sales (A6)	264,157	897,600	(633,443)	(70.6)	16,664	61,200	(44,536)	(72.8)	1.58520	1.46667	0.11853	8.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,725,298	4,040,220	(1,314,922)	(32.5)	160,276	224,997	(64,721)	(28.8)	1.70038	1.79568	(0.09530)	(5.3)
23. Net Inadvertant Interchange					595	0	595	0.0				
24. Wheeling Rec'd. less Wheeling Delv'd.					616	0	616	0.0				
25. Interchange and Wheeling Losses					3,265	3,400	(135)	(4.0)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	25,556,917	27,357,415	(1,800,498)	(6.6)	1,226,661	1,225,403	1,258	0.1	2.08345	2.23252	(0.14907)	(6.7)
27. Net Unbilled	(66,754) (a)	44,226 (a)	(110,980)	(250.9)	(3,204)	1,981	(5,185)	(261.7)	(0.00544)	0.00361	(0.00905)	(250.7)
28. Company Use	74,442 (a)	84,836 (a)	(10,394)	(12.3)	3,573	3,800	(227)	(6.0)	0.00633	0.00731	(0.00098)	(13.4)
29. T & D Losses	1,029,516 (a)	1,332,881 (a)	(303,365)	(22.8)	49,414	59,703	(10,289)	(17.2)	0.08748	0.11491	(0.02743)	(23.9)
30. System KWH Sales	25,556,917	27,357,415	(1,800,498)	(6.6)	1,176,878	1,159,919	16,959	1.5	2.17159	2.35856	(0.18697)	(7.9)
31. Wholesale KWH Sales	(236,227)	(79,744)	(154,483)	193.7	(10,786)	(3,381)	(7,405)	219.0	2.17158	2.35859	(0.18701)	(7.9)
32. Jurisdictional KWH Sales	25,322,690	27,277,671	(1,954,981)	(7.2)	1,166,092	1,156,538	9,554	0.8	2.17159	2.35856	(0.18697)	(7.9)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	25,325,982	27,281,217	(1,955,235)	(7.2)	1,166,092	1,156,538	9,554	0.8	2.17187	2.35887	(0.18700)	(7.9)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	422,211	427,865	(5,654)	(1.3)	1,166,092	1,156,538	9,554	0.8	0.03621	0.03700	(0.00079)	(2.1)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(517,734)	504,555	(97.5)	1,166,092	1,156,538	9,554	0.8	(0.00113)	(0.04477)	0.04364	(97.5)
37. True-up *	(728,854)	(728,854)	0	0.0	1,166,092	1,156,538	9,554	0.8	(0.06250)	(0.06302)	0.00052	(0.8)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	25,006,160	26,462,494	(1,456,334)	(5.5)	1,166,092	1,156,538	9,554	0.8	2.14444	2.28808	(0.14364)	(6.3)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.14622	2.28998	(0.14376)	(6.3)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,166,092	1,156,538	9,554	0.8	(0.00520)	(0.00524)	0.00004	(0.8)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	24,945,569	26,401,903	(1,456,334)	(5.5)	1,166,092	1,156,538	9,554	0.8	2.14102	2.28474	(0.14372)	(6.3)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.141	2.285	(0.144)	(6.3)

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: APRIL, 1998

SCHEDULE A1

	$				KWH				cents/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (A3)	27,437,874	29,909,035	(2,471,161)	(8.3)	1,329,967	1,400,925	(70,958)	(5.1)	2.06305	2.13495	(0.07190)	(3.4)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(2,990)	(3,500)	510	(14.6)	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	(0.00022)	(0.00025)	0.00003	(12.0)
4b. Adjustments to Fuel Cost	0	0	0	0.0	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	0.00000	0.00000	0.00000	0.0
4c. Adjustments to Fuel Cost	0	0	0	0.0	1,329,967 (a)	1,400,925 (a)	(70,958)	(5.1)	0.00000	0.00000	0.00000	0.0
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)	27,434,884	29,905,535	(2,470,651)	(8.3)	1,329,967	1,400,925	(70,958)	(5.1)	2.06282	2.13470	(0.07188)	(3.4)
6. Fuel Cost of Purchased Power - Firm (A7)	195,778	511,800	(316,022)	(61.7)	18,616	12,338	6,286	51.0	1.05167	4.15085	(3.09918)	(74.7)
7. Energy Cost of Sch C,I Economy Purchases (Broker) (A9)	13,228	80,700	(67,472)	(83.6)	466	1,868	(1,402)	(75.1)	2.83863	4.32013	(1.48150)	(34.3)
8. Energy Cost of Other Economy Purchases (Non-Broker) (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0 (a)	0 (a)	0	0.0	0.00000	0.00000	0.00000	0.0
11. Payments to Qualifying Facilities (A8)	638,325	899,680	(261,275)	(29.0)	39,942	38,677	1,265	3.3	1.59813	2.32593	(0.72780)	(31.3)
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	847,331	1,492,180	(644,769)	(43.2)	59,024	52,875	6,149	11.6	1.43557	2.82194	(1.38637)	(49.1)
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,388,991	1,453,800	(64,809)	(4.5)				
14. Fuel Cost of Economy Sales (A6)	1,307,746	1,590,800	(283,054)	(17.8)	94,397	103,172	(8,775)	(8.5)	1.38537	1.54189	(0.15652)	(10.2)
15. Gain on Economy Sales - 80% (A6)	316,582	432,720	(116,138)	(26.8)	94,397 (a)	103,172 (a)	(8,775)	(8.5)	0.33537	0.41942	(0.08405)	(20.0)
16. Fuel Cost of Sch. B Separ. Sales (A6)	402,503	424,100	(21,597)	(5.1)	28,807	29,440	(633)	(2.2)	1.39724	1.44056	(0.04332)	(3.0)
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	83,332	57,200	26,132	45.7	5,685	3,554	2,131	60.0	1.46582	1.60945	(0.14363)	(8.9)
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
19. Fuel Cost of Sch. J Jurisd. Sales (A6)	131,134	129,700	1,434	1.1	5,471	5,400	71	1.3	2.39689	2.40185	(0.00496)	(0.2)
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	219,844	508,100	(288,256)	(56.7)	9,252	22,231	(12,979)	(58.4)	2.37618	2.28555	0.09063	4.0
21. Fuel Cost of Other Power Sales (A6)	264,151	897,600	(633,443)	(70.6)	16,664	61,200	(44,536)	(72.8)	1.58520	1.46667	0.11853	8.1
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21)	2,725,298	4,040,220	(1,314,922)	(32.5)	160,276	224,997	(64,721)	(28.8)	1.70038	1.79568	(0.09530)	(5.3)
23. Net Inadvertant Interchange					595	0	595	0.0				
24. Wheeling Rec'd. less Wheeling Dely'd.					616	0	616	0.0				
25. Interchange and Wheeling Losses					3,265	3,408	(135)	(4.0)				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	25,556,917	27,357,415	(1,800,498)	(6.6)	1,226,661	1,225,403	1,258	0.1	2.08345	2.23252	(0.14907)	(6.7)
27. Net Unbilled	(66,754) (a)	44,226 (a)	(110,980)	(250.9)	(3,204)	1,981	(5,185)	(261.7)	(0.00544)	0.00361	(0.00905)	(250.7)
28. Company Use	74,442 (a)	84,836 (a)	(10,394)	(12.3)	3,573	3,800	(227)	(6.0)	0.00633	0.00731	(0.00098)	(13.4)
29. T & D Losses	1,029,516 (a)	1,332,881 (a)	(303,365)	(22.8)	49,414	59,703	(10,289)	(17.2)	0.08748	0.11491	(0.02743)	(23.9)
30. System KWH Sales	25,556,917	27,357,415	(1,800,498)	(6.6)	1,176,878	1,159,918	16,959	1.5	2.17159	2.35856	(0.18697)	(7.9)
31. Wholesale KWH Sales	(234,227)	(79,744)	(154,483)	193.7	(10,786)	(3,381)	(7,405)	219.0	2.17158	2.35859	(0.18701)	(7.9)
32. Jurisdictional KWH Sales	25,322,690	27,277,671	(1,954,981)	(7.2)	1,166,092	1,156,538	9,554	0.8	2.17159	2.35856	(0.18697)	(7.9)
33. Jurisdictional Loss Multiplier - 1.00013												
34. Jurisdictional KWH Sales Adjusted for Line Losses	25,325,982	27,281,217	(1,955,235)	(7.2)	1,166,092	1,156,538	9,554	0.8	2.17187	2.35887	(0.18700)	(7.9)
35. Peabody Coal Contract Buy-Out Amort. Jurisdictionalized	422,211	427,865	(5,654)	(1.3)	1,166,092	1,156,538	9,554	0.8	0.03621	0.03700	(0.00079)	(2.1)
36. Fuel Credit Differential - FMPA Sale	(13,179)	(517,734)	504,555	(97.5)	1,166,092	1,156,538	9,554	0.8	(0.00113)	(0.04477)	0.04364	(97.5)
37. True-up *	(728,854)	(728,854)	0	0.0	1,166,092	1,156,538	9,554	0.8	(0.06250)	(0.06302)	0.00052	(0.8)
38. Total Jurisdictional Fuel Cost (Excl. GPIF)	25,006,160	26,462,494	(1,456,334)	(5.5)	1,166,092	1,156,538	9,554	0.8	2.14444	2.28808	(0.14364)	(6.3)
39. Revenue Tax Factor									1.00083	1.00083	0.00000	0.0
40. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.14622	2.28998	(0.14376)	(6.3)
41. GPIF * (Already Adjusted for Taxes)	(60,591)	(60,591)	0	0.0	1,166,092	1,156,538	9,554	0.8	(0.00520)	(0.00524)	0.00004	(0.8)
42. Fuel Cost Adjusted for Taxes (Incl. GPIF)	24,945,569	26,401,903	(1,456,334)	(5.5)	1,166,092	1,156,538	9,554	0.8	2.14102	2.28474	(0.14372)	(6.3)
43. Fuel FAC Rounded to the Nearest .001 cents per KWH									2.141	2.285	(0.144)	(6.3)

* Based on Jurisdictional Sales (a) Included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	27,437,874	29,909,035	(2,471,161)	(8.3)	27,437,874	29,909,035	(2,471,161)	(8.3)
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0	0	0	0	0.0
2. FUEL COST OF POWER SOLD *	2,725,298	4,040,220	(1,314,922)	(32.5)	2,725,298	4,040,220	(1,314,922)	(32.5)
3. FUEL COST OF PURCHASED POWER	195,778	511,800	(316,022)	(61.7)	195,778	511,800	(316,022)	(61.7)
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0	0	0	0	0.0
b. PAYMENT TO QUALIFIED FACILITIES	638,325	899,600	(261,275)	(29.0)	638,325	899,600	(261,275)	(29.0)
4. ENERGY COST OF ECONOMY PURCHASES	13,228	80,700	(67,472)	(83.6)	13,228	80,700	(67,472)	(83.6)
5. TOTAL FUEL & NET POWER TRANSACTION	25,559,907	27,360,915	(1,801,008)	(6.6)	25,559,907	27,360,915	(1,801,008)	(6.6)
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(2,990)	(3,500)	510	(14.6)	(2,990)	(3,500)	510	(14.6)
6b. ADJUSTMENTS TO FUEL COST	0	0	0	0.0	0	0	0	0.0
6c. ADJ.TO FUEL COST	0	0	0	0.0	0	0	0	0.0
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	25,556,917	27,357,415	(1,800,498)	(6.6)	25,556,917	27,357,415	(1,800,498)	(6.6)
* INCLUDES ECONOMY SALES PROFITS (80%)								
B. MWH SALES								
1. JURISDICTIONAL SALES	1,166,092	1,156,538	9,554	0.8	1,166,092	1,156,538	9,554	0.8
2. NONJURISDICTIONAL SALES	10,786	3,381	7,405	219.0	10,786	3,381	7,405	219.0
3. TOTAL SALES	1,176,878	1,159,919	16,959	1.5	1,176,878	1,159,919	16,959	1.5
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9908351	0.9970851	(0.0062500)	(0.6)	0.9908351	0.9970851	(0.0062500)	(0.6)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

C. TRUE-UP CALCULATION	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE %
1. JURISDICTIONAL FUEL REVENUE	26,976,474	26,996,593	(20,119)	(0.1)	26,976,474	26,996,593	(20,119)	(0.1)
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0	0	0	0	0.0
a. TRUE-UP PROVISION	728,854	728,854	0	0.0	728,854	728,854	0	0.0
b. INCENTIVE PROVISION	60,591	60,591	0	0.0	60,591	60,591	0	0.0
c. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
3. JURIS. FUEL REVENUE APPL. TO PERIOD	27,765,919	27,786,038	(20,119)	(0.1)	27,765,919	27,786,038	(20,119)	(0.1)
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A-7)	25,556,917	27,357,415	(1,800,498)	(6.6)	25,556,917	27,357,415	(1,800,498)	(6.6)
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B-4)	0.9908351	0.9970851	(0.0062500)	(0.6)	NA	NA	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	25,322,690	27,277,671	(1,954,981)	(7.2)	25,322,690	27,277,671	(1,954,981)	(7.2)
6A.JURISDIC. LOSS MULTIPLIER	1.00013	1.00013	0.0000	0.0	NA	NA	-	-
6B.(LINE 6 x LINE 6A)	25,325,982	27,281,217	(1,955,235)	(7.2)	25,325,982	27,281,217	(1,955,235)	(7.2)
6C.PEABODY COAL CONTRACT BUY-OUT AMORT.	426,116	429,116	(3,000)	(0.7)	426,116	429,116	(3,000)	(0.7)
6D.(LINE 6C x LINE 5)	422,211	427,865	(5,654)	(1.3)	422,211	427,865	(5,654)	(1.3)
6E. FUEL CREDIT DIFFERENTIAL-FMPA	(13,179)	(517,734)	504,555	(97.5)	(13,179)	(517,734)	504,555	(97.5)
6F. OTHER ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
6G. JURISDIC. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY AND ADJUSTMENTS	25,735,014	27,191,348	(1,456,334)	(5.4)	25,735,014	27,191,348	(1,456,334)	(5.4)
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C-3 - LINE C-6G)	2,030,905	594,690	1,436,215	241.5	2,030,905	594,690	1,436,215	241.5
8. INTEREST PROVISION FOR THE MONTH	23,458	21,530	1,928	9.0	23,458	21,530	1,928	9.0
9. TRUE-UP & INT. PROV. BEG. OF MONTH	10,468,942	10,415,528	53,414	0.5	NOT APPLICABLE			
9a.DEFERRED TRUE-UP BEGINNING OF PERIOD	(6,042,407)	(6,042,407)	0	0.0	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	(728,854)	(728,854)	0	0.0	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C-7 through C-10)	5,752,044	4,260,487	1,491,557	35.0	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C-9 + C-9a)	4,426,535	4,373,121	53,414	1.2	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C-7 + C-9 + C-9a + C-10)	5,728,586	4,238,957	1,489,629	35.1	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	10,155,121	8,612,078	1,543,043	17.9	NOT APPLICABLE			
4. AVG. TRUE-UP AMT. (50% OF LINE D-3)	5,077,561	4,306,039	771,522	17.9	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	5.550	6.000	(0.450)	(7.5)	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	5.530	6.000	(0.470)	(7.8)	NOT APPLICABLE			
7. TOTAL (LINE D-5 + LINE D-6)	11.080	12.000	(0.920)	(7.7)	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D-7)	5.540	6.000	(0.460)	(7.7)	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D-8/12)	0.462	0.500	(0.038)	(7.6)	NOT APPLICABLE			
10. INT. PROVISION (LINE D-4 x LINE D-9)	23,458	21,530	1,928	9.0	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL, 1998

SCHEDULE A3
PAGE 1 OF 2

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	209,790	509,526	(299,736)	(58.8)	209,790	509,526	(299,736)	(58.8)
2	LIGHT OIL	801,082	775,455	25,627	3.3	801,082	775,455	25,627	3.3
3	COAL	26,427,002	28,624,054	(2,197,052)	(7.7)	26,427,002	28,624,054	(2,197,052)	(7.7)
4	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
5	NUCLEAR	0	0	0	0.0	0	0	0	0.0
6	OTHER	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	27,437,874	29,909,035	(2,471,161)	(8.3)	27,437,874	29,909,035	(2,471,161)	(8.3)
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	5,741	11,276	(5,535)	(49.1)	5,741	11,276	(5,535)	(49.1)
9	LIGHT OIL	25,755	17,201	8,554	49.7	25,755	17,201	8,554	49.7
10	COAL	1,298,471	1,372,448	(73,977)	(5.4)	1,298,471	1,372,448	(73,977)	(5.4)
11	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
12	NUCLEAR	0	0	0	0.0	0	0	0	0.0
13	OTHER	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	1,329,967	1,400,925	(70,958)	(5.1)	1,329,967	1,400,925	(70,958)	(5.1)
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	11,127	26,142	(15,015)	(57.4)	11,127	26,142	(15,015)	(57.4)
16	LIGHT OIL (BBL)	38,064	27,739	10,325	37.2	38,064	27,739	10,325	37.2
17	COAL (TON)	619,012	611,778	7,234	1.2	619,012	611,778	7,234	1.2
18	NATURAL GAS (MCF)	0	0	0	0.0	0	0	0	0.0
19	NUCLEAR (MMBTU)	0	0	0	0.0	0	0	0	0.0
20	OTHER (MMBTU)	0	0	0	0.0	0	0	0	0.0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	70,025	165,247	(95,222)	(57.6)	70,025	165,247	(95,222)	(57.6)
22	LIGHT OIL	216,131	160,905	55,226	34.3	216,131	160,905	55,226	34.3
23	COAL	13,825,326	14,018,283	(192,957)	(1.4)	13,825,326	14,018,283	(192,957)	(1.4)
24	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
25	NUCLEAR	0	0	0	0.0	0	0	0	0.0
26	OTHER	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	14,111,482	14,344,435	(232,953)	(1.6)	14,111,482	14,344,435	(232,953)	(1.6)
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.43	0.80	(0.37)	-	0.43	0.80	(0.37)	-
29	LIGHT OIL	1.94	1.23	0.71	-	1.94	1.23	0.71	-
30	COAL	97.63	97.97	(0.34)	-	97.63	97.97	(0.34)	-
31	NATURAL GAS	0.00	0.00	0.00	-	0.00	0.00	0.00	-
32	NUCLEAR	0.00	0.00	0.00	-	0.00	0.00	0.00	-
33	OTHER	0.00	0.00	0.00	-	0.00	0.00	0.00	-
34	TOTAL (%)	100.00	100.00	0.00	-	100.00	100.00	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	18.85	19.49	(0.64)	(3.3)	18.85	19.49	(0.64)	(3.3)
36	LIGHT OIL ($/BBL)	21.05	27.96	(6.91)	(24.7)	21.05	27.96	(6.91)	(24.7)
37	COAL ($/TON)	42.69	46.79	(4.10)	(8.8)	42.69	46.79	(4.10)	(8.8)
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	3.00	3.08	(0.08)	(2.6)	3.00	3.08	(0.08)	(2.6)
42	LIGHT OIL	3.71	4.82	(1.11)	(23.0)	3.71	4.82	(1.11)	(23.0)
43	COAL	1.91	2.04	(0.13)	(6.4)	1.91	2.04	(0.13)	(6.4)
44	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
45	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
46	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	TOTAL ($/MMBTU)	1.94	2.09	(0.15)	(7.2)	1.94	2.09	(0.15)	(7.2)

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF: APRIL, 1998

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	12,197	14,655	(2,458)	(16.8)	12,197	14,655	(2,458)	(16.8)
49	LIGHT OIL	8,392	9,354	(962)	(10.3)	8,392	9,354	(962)	(10.3)
50	COAL	10,647	10,214	433	4.2	10,647	10,214	433	4.2
51	NATURAL GAS	0	0	0	0.0	0	0	0	0.0
52	NUCLEAR	0	0	0	0.0	0	0	0	0.0
53	OTHER	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	10,610	10,239	371	3.6	10,610	10,239	371	3.6
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.65	4.52	(0.87)	(19.2)	3.65	4.52	(0.87)	(19.2)
56	LIGHT OIL	3.11	4.51	(1.40)	(31.0)	3.11	4.51	(1.40)	(31.0)
57	COAL	2.04	2.09	(0.05)	(2.4)	2.04	2.09	(0.05)	(2.4)
58	NATURAL GAS	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
59	NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
60	OTHER	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	TOTAL (cents/KWH)	2.06	2.13	(0.07)	(3.3)	2.06	2.13	(0.07)	(3.3)

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD/MONTH OF: APRIL, 1998

SCHEDULE A4

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	NET CAPC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents /KWH)	COST OF FUEL ($/UNIT)
H.P.#1	32	355	1.5	100.0	34.4	-	HVY.OIL	-	-	-	-	-	-
H.P.#2	32	131	0.6	100.0	41.9	-	HVY.OIL	-	-	-	-	-	-
H.P.#3	32	430	1.9	100.0	46.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#4	41	469	1.6	100.0	42.2	-	HVY.OIL	-	-	-	-	-	-
H.P.#5	67	0	0.0	0.0	0.0	-	HVY.OIL	-	-	-	-	-	-
H.P. STATION	204	1385	0.9	67.2	27.7	21150	HVY.OIL	4634	6321234	29292.6	74978	5.41	16.18
GAN.#1	114	29763	36.3	56.7	69.4	11481	COAL	16492	20719640	341708.3	711022	2.39	43.11
GAN.#2	108	37045	47.7	69.8	65.5	12988	COAL	26114	18425159	481154.6	1125856	3.04	43.11
GAN.#3	155	69043	62.0	90.8	69.3	11771	COAL	42629	19065040	812723.6	1837869	2.66	43.11
GAN.#4	169	89359	73.5	97.2	76.9	11772	COAL	55428	18979180	1051978.0	2389674	2.67	43.11
GAN.#5	227	124146	76.1	86.9	82.9	10537	COAL	55325	23645359	1308179.5	2385233	1.92	43.11
GAN.#6	362	215415	82.8	95.4	83.3	10491	COAL	91298	24753720	2259965.1	3936142	1.83	43.11
GANNON STA.	1135	564771	69.2	87.0	77.3	11077	COAL	287286	21775196	6255709.1	12385796	2.19	43.11
B.B.#1	421	242547	80.1	94.3	82.7	9868	COAL	104287	22951440	2393536.8	4259607	1.76	40.85
B.B.#2	416	0	0.0	0.0	0.0	0	COAL	0	ERR	0.0	0	0.00	0.00
B.B.#3	428	179880	58.5	69.7	74.8	10406	COAL	79489	23549000	1871886.5	3246732	1.80	40.85
B.B. 1 - 3	1265	422427	46.4	55.0	52.8	10097	COAL	183776	23209904	4265423.3	7506339	1.78	40.85
B.B.#4	442	239459	75.3	85.8	84.0	10122	COAL	109623	22110527	2423822.3	4791251	2.00	43.71
B.B. STA.	1707	661886	53.9	62.9	60.9	10106	COAL	293399	22799142	6689245.6	12297590	1.86	41.91
SEB-PHIL. #1(HVY OIL)	17	2126	17.4	99.8	82.4	9352	HVY.OIL	3169	6273809	19881.7	65797	3.09	20.76
SEB-PHIL. #2(HVY OIL)	17	2230	18.2	99.8	86.1	9350	HVY.OIL	3324	6272744	20850.6	69015	3.09	20.76
SEB-PHILLIPS TOTAL	34	4356	17.8	99.8	84.3	9351	HVY.OIL	6493	6273264	40732.3	134812	3.09	20.76
POLK COAL	250	71814	40.0	47.3	84.5	12259	COAL	38327	22970000	880371.2	1743616	2.43	45.49
POLK OIL	225	25034	15.5	43.1	64.0	8138	LGT.OIL	35924	5671295	203735.6	754972	3.02	21.02
POLK TOTAL	250	96848	55.5	90.4	-	11194	-	-	-	1084106.8	2498588	2.58	-
GAN.C.T.#1	15	7	0.1	100.0	46.7	24943	LGT.OIL	30	5820000	174.6	646	9.23	21.53
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	65	279	0.6	100.0	61.3	16546	LGT.OIL	797	5791970	4616.2	17173	6.16	21.55
B.B.C.T.#3	65	435	0.9	100.0	60.8	17481	LGT.OIL	1313	5791622	7604.4	28291	6.50	21.55
C.T. TOTAL	160	721	0.6	100.0	54.0	17192	LGT.OIL	2140	5792150	12395.2	46110	6.40	21.55
TOT. COAL (GN,BB,POLK)	3092	1298471	58.4	70.5	68.8	10647	COAL	619012	22334504	13825325.9	26427002	2.04	42.69
SYSTEM	3490	1329967	53.0	72.0	65.9	10610	-	-	-	14111481.6	27437874	2.06	-

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
SEB-PHIL. = SEBRING-PHILLIPS
GAN. = GANNON
C.T. = COMBUSTION TURBINE

NA = LESS THAN 1 HOUR OF OPERATION

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

			CURRENT MONTH				PERIOD TO DATE			
			ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	HEAVY OIL (1)									
1	PURCHASES:									
2	UNITS (BBL)		483	26,142	(25,659)	(98.2)	483	26,142	(25,659)	(98.2)
3	UNIT COST ($/BBL)	*	(475.21)	17.71	(492.92)	(2,783.3)	(475.21)	17.71	(492.92)	(2,783.3)
4	AMOUNT ($)	*	(229,527)	463,013	(692,540)	(149.6)	(229,527)	463,013	(692,540)	(149.6)
5	BURNED:									
6	UNITS (BBL)		11,127	26,142	(15,015)	(57.4)	11,127	26,142	(15,015)	(57.4)
7	UNIT COST ($/BBL)		18.85	19.49	(0.64)	(3.3)	18.85	19.49	(0.64)	(3.3)
8	AMOUNT ($)		209,790	509,526	(299,736)	(58.8)	209,790	509,526	(299,736)	(58.8)
9	ENDING INVENTORY:									
10	UNITS (BBL)		179,950	139,530	40,420	29.0	179,950	139,530	40,420	29.0
11	UNIT COST ($/BBL)		16.42	17.96	(1.54)	(8.6)	16.42	17.96	(1.54)	(8.6)
12	AMOUNT ($)		2,954,247	2,505,266	448,981	17.9	2,954,247	2,505,266	448,981	17.9
13										
14	DAYS SUPPLY:		170	132	38	28.8	-	-	-	-
	LIGHT OIL (2)									
15	PURCHASES:									
16	UNITS (BBL)		42,306	38,632	3,674	9.5	42,306	38,632	3,674	9.5
17	UNIT COST ($/BBL)		17.37	27.96	(10.59)	(37.9)	17.37	27.96	(10.59)	(37.9)
18	AMOUNT ($)		735,033	1,080,009	(344,976)	(31.9)	735,033	1,080,009	(344,976)	(31.9)
19	BURNED:									
20	UNITS (BBL)		38,064	27,739	10,325	37.2	38,064	27,739	10,325	37.2
21	UNIT COST ($/BBL)		21.05	27.96	(6.91)	(24.7)	21.05	27.96	(6.91)	(24.7)
22	AMOUNT ($)		801,082	775,455	25,627	3.3	801,082	775,455	25,627	3.3
23	ENDING INVENTORY:									
24	UNITS (BBL)		83,406	60,844	22,562	37.1	83,406	60,844	22,562	37.1
25	UNIT COST ($/BBL)		21.35	27.98	(6.63)	(23.7)	21.35	27.98	(6.63)	(23.7)
26	AMOUNT ($)		1,780,550	1,702,619	77,931	4.6	1,780,550	1,702,619	77,931	4.6
27										
28	DAYS SUPPLY: NORMAL		68	49	19	38.8	-	-	-	-
29	DAYS SUPPLY: EMERGENCY		12	9	3	33.3	-	-	-	-
	COAL (3)									
30	PURCHASES:									
31	UNITS (TONS)		575,202	712,500	(137,298)	(19.3)	575,202	712,500	(137,298)	(19.3)
32	UNIT COST ($/TON)		41.78	45.53	(3.75)	(8.2)	41.78	45.53	(3.75)	(8.2)
33	AMOUNT ($)		24,032,963	32,442,068	(8,409,105)	(25.9)	24,032,963	32,442,068	(8,409,105)	(25.9)
34	BURNED:									
35	UNITS (TONS)		619,012	611,778	7,234	1.2	619,012	611,778	7,234	1.2
36	UNIT COST ($/TON)		42.69	46.79	(4.10)	(8.8)	42.69	46.79	(4.10)	(8.8)
37	AMOUNT ($)		26,427,002	28,624,054	(2,197,052)	(7.7)	26,427,002	28,624,054	(2,197,052)	(7.7)
38	ENDING INVENTORY:									
39	UNITS (TONS)		588,519	629,071	(40,552)	(6.4)	588,519	629,071	(40,552)	(6.4)
40	UNIT COST ($/TON)		41.27	45.98	(4.71)	(10.2)	41.27	45.98	(4.71)	(10.2)
41	AMOUNT ($)		24,290,642	28,927,310	(4,636,668)	(16.0)	24,290,642	28,927,310	(4,636,668)	(16.0)
42										
43	DAYS SUPPLY:		25	27	(2)	(7.4)	-	-	-	-
	NATURAL GAS									
44	PURCHASES:									
45	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
46	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
47	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
48	BURNED:									
49	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
50	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
51	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
52	ENDING INVENTORY:									
53	UNITS (MCF)		0	0	0	0.0	0	0	0	0.0
54	UNIT COST ($/MCF)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
55	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0
56										
57	DAYS SUPPLY:		0	0	0	0.0	-	-	-	-
	NUCLEAR									
58	BURNED:									
59	UNITS (MMBTU)		0	0	0	0.0	0	0	0	0.0
60	UNIT COST ($/MMBTU)		0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
61	AMOUNT ($)		0	0	0	0.0	0	0	0	0.0

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL, 1998

	OTHER	CURRENT MONTH ACTUAL	CURRENT MONTH ESTIMATED	CURRENT MONTH DIFFERENCE AMOUNT	CURRENT MONTH DIFFERENCE %	PERIOD TO DATE ACTUAL	PERIOD TO DATE ESTIMATED	PERIOD TO DATE DIFFERENCE AMOUNT	PERIOD TO DATE DIFFERENCE %
62	PURCHASES:								
63	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
65	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
66	BURNED:								
67	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
69	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
70	ENDING INVENTORY:								
71	UNITS (MMBTU)	0	0	0	0.0	0	0	0	0.0
72	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
73	AMOUNT ($)	0	0	0	0.0	0	0	0	0.0
74	DAYS SUPPLY:	0	0	0	0.0	-	-	-	-

* INCLUDES ADJUSTMENT OF ($255,944.91)

(1)RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	0
LUBE OIL	0
FUEL ANALYSIS	6,732
TOTAL	6,732

(2)
RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
IGNITION	(10,044)	(216,140)
OTHER USAGE	(4,869)	(102,506)
TOTAL	(14,913)	(318,646)

(3)
RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	20,344
IGNITION #2 OIL	209,408
IGNITION PROPANE	4,629
AERIAL SURVEY ADJ.	(36,395)
ADDITIVES	57,733
TOTAL	255,719

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF APRIL, 1998

SCHEDULE A6
PAGE 1 OF 2

(1) SOLD TO		(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
ESTIMATED:										
VARIOUS		ECON.	103,172.0	0.0	103,172.0	1.669	2.193	1,721,800.00	2,262,700.00	432,720.00
VARIOUS	JURISDICTIONAL	SCH. -D	3,554.0	0.0	3,554.0	1.609	1.609	57,200.00	57,200.00	
VARIOUS	SEPARATED	SCH. -D	29,440.0	0.0	29,440.0	1.441	1.688	424,100.00	497,000.00	
VARIOUS		CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPARATED	CONTRACT	22,231.0	0.0	22,231.0	2.286	3.094	508,100.00	687,800.00	
VARIOUS		SCH. -D	61,200.0	0.0	61,200.0	1.467	1.563	897,600.00	956,600.00	
VARIOUS	JURISDICTIONAL	SCH. -J	5,400.0	0.0	5,400.0	2.402	2.402	129,700.00	129,700.00	
TOTAL INCLUDING VARIABLE O & M COSTS		-	224,997.0	0.0	224,997.0	1.662	2.040	3,738,500.00	4,591,000.00	432,720.00
LESS TRANSMISSION COSTS		-						0.00		
LESS VARIABLE O & M COSTS		-						(131,000.00)		
PLUS 80% OF ECON. ENERGY SALES PROFITS		-						432,720.00		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS		-	224,997.0	0.0	224,997.0	1.796	2.040	4,040,220.00	4,591,000.00	432,720.00
ACTUAL:										
FLA. PWR. CORP.		ECON.-C	5,952.0	0.0	5,952.0	1.613	2.270	96,004.65	135,110.19	31,284.43
FLA. PWR. & LIGHT		ECON.-C	35,165.0	0.0	35,165.0	1.546	1.819	543,620.95	639,714.41	76,874.76
CITY OF LAKELAND		ECON.-C	6,400.0	0.0	6,400.0	1.658	2.256	106,085.91	144,400.00	30,651.27
FT. PIERCE UTIL. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF GAINESVILLE		ECON.-C	1,102.0	0.0	1,102.0	1.562	2.455	17,215.54	27,049.25	7,866.97
CITY OF HOMESTEAD		ECON.-C	94.0	0.0	94.0	1.522	2.119	1,430.67	1,991.97	449.04
JACKSONVILLE ELEC. AUTH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
KISSIMMEE ELEC. UTIL.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
LAKE WORTH UTILITIES		ECON.-C	221.0	0.0	221.0	1.589	2.954	3,512.05	6,528.77	2,413.38
CITY OF NEW SMYRNA BCH.		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		ECON.-C	16,886.0	0.0	16,886.0	1.541	1.886	260,216.55	318,416.52	46,559.98
SEMINOLE ELECTRIC CO-OP		ECON.-C	5,071.0	0.0	5,071.0	1.551	2.019	78,647.33	102,403.25	19,004.74
CITY OF ST. CLOUD		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF STARKE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF VERO BEACH		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FMPA		ECON.-C	501.0	0.0	501.0	1.588	1.968	7,957.48	9,862.07	1,523.67
KEY WEST		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		ECON.-C	20,675.0	0.0	20,675.0	1.520	2.050	314,170.62	423,779.42	87,687.04
SONAT		ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		ECON.-C	80.0	0.0	80.0	1.695	3.213	1,356.00	2,570.00	971.20
NP ENERGY INC.		ECON.-C	2,250.0	0.0	2,250.0	1.528	2.121	34,388.00	47,725.00	10,669.60
FLA. PWR. & LIGHT	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPAR.	SCH. -D	7,723.0	0.0	7,723.0	1.723	1.867	133,104.63	144,188.24	
REEDY CREEK	SEPAR.	SCH. -D	14,360.0	0.0	14,360.0	1.357	1.628	194,865.20	233,780.80	
WAUCHULA	SEPAR.	SCH. -D	3,600.0	0.0	3,600.0	1.357	1.628	48,852.00	58,608.00	
FT. MEADE	SEPAR.	SCH. -D	3,124.0	0.0	3,124.0	1.357	1.628	42,392.68	50,858.72	
CITY OF ST. CLOUD	SEPAR.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PARTNERS	SEPAR.	CONTRACT	9,252.0	0.0	9,252.0	2.296	2.969	212,425.92	274,691.88	
SEMINOLE ELECTRIC CO-OP PRECO-1	JURISD.	SCH. -D	5,020.0	10.4	5,009.6	1.470	1.470	73,638.72	73,638.72	
SEMINOLE ELECTRIC CO-OP HARDEE	JURISD.	SCH. -D	675.0	0.0	675.0	1.436	1.436	9,693.13	9,693.13	
FLA. PWR. CORP.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF HOMESTEAD	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KEY WEST	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTIL. COMM.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	JURISD.	SCH. -J	5,471.0	0.0	5,471.0	2.397	2.397	131,134.07	131,134.07	
SEMINOLE ELECTRIC CO-OP	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF VERO BEACH	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
LAKE WORTH UTILITIES	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
OGLETHORPE	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF APRIL, 1998

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) cents/KWH (A) FUEL COST	(6) cents/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6)(A)	(8) TOTAL $ FOR TOTAL COST (5)X(6)(B)	(9) 80% GAIN ON ECONOMY ENERGY SALES
FMPA	SCH. -D	61,115.0	44,451.0	16,664.0	1.776	1.753	296,016.79	292,154.68	
CITY OF LAKELAND	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE POWER PART. TO FLA. PWR. CORP.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FLA. PWR.& LT.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO REEDY CREEK	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO GAINESVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO JACKSONVILLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KISSIMMEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO NEW SMYRNA BCH.	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ORLANDO	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO STARKE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FMPA	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 ●
HARDEE POWER PART. TO HOMESTEAD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO SEMINOLE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO FT. PIERCE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO TALLAHASSEE	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO LAKELAND	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO ST. CLOUD	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO KEY WEST	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 *
HARDEE POWER PART. TO VERO BEACH	ECON.-C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00 ●
ADJUSTMENTS TO PRIOR MONTHS									
HARDEE POWER PARTNERS 3/98 SEPAR.	CONTRACT	(9,891.0)	0.0	(9,891.0)	2.221	2.906	(219,679.11)	(287,432.46)	
HARDEE POWER PARTNERS 3/98 SEPAR.	CONTRACT	9,891.0	0.0	9,891.0	2.296	2.969	227,097.36	293,663.79	
HARDEE POWER PART. TO FPC 2/98	ECON.-C	(91.0)	0.0	(91.0)	1.942	2.079	(1,767.22)	(1,892.03)	(99.85)*
HARDEE POWER PART. TO FPC 2/98	ECON.-C	91.0	0.0	91.0	1.942	2.181	1,767.22	1,984.58	173.89 *
HARDEE POWER PART. TO FPL 2/98	ECON.-C	(31.0)	0.0	(31.0)	1.869	1.933	(579.39)	(599.23)	(15.87)*
HARDEE POWER PART. TO FPL 2/98	ECON.-C	31.0	0.0	31.0	1.869	2.047	579.39	634.71	44.26 *
HARDEE POWER PART. TO ORLANDO 2/98	ECON.-C	(125.0)	0.0	(125.0)	1.942	2.106	(2,427.50)	(2,632.76)	(164.21)*
HARDEE POWER PART. TO ORLANDO 2/98	ECON.-C	125.0	0.0	125.0	1.942	2.206	2,427.50	2,757.63	264.10 *
HARDEE POWER PART. TO FPC 3/98	ECON.-C	(196.0)	0.0	(196.0)	1.799	1.939	(3,525.18)	(3,801.29)	(220.89)*
HARDEE POWER PART. TO FPC 3/98	ECON.-C	196.0	0.0	196.0	1.799	2.041	3,525.18	3,999.70	379.62 *
HARDEE POWER PART. TO ORLANDO 3/98	ECON.-C	(140.0)	0.0	(140.0)	1.765	1.866	(2,470.60)	(2,611.78)	(112.94)*
HARDEE POWER PART. TO ORLANDO 3/98	ECON.-C	140.0	0.0	140.0	1.765	1.965	2,470.60	2,750.93	224.26 *
HARDEE POWER PART. TO FMPA 3/98	ECON.-C	(36.0)	0.0	(36.0)	1.843	2.143	(663.45)	(771.39)	(86.35)*
HARDEE POWER PART. TO FMPA 3/98	ECON.-C	36.0	0.0	36.0	1.843	2.255	663.45	811.63	118.54 *
HARDEE POWER PART. TO LAKE WTH 3/98	ECON.-C	(17.0)	0.0	(17.0)	1.857	2.084	(315.67)	(354.36)	(30.95)*
HARDEE POWER PART. TO LAKE WTH 3/98	ECON.-C	17.0	0.0	17.0	1.857	2.215	315.67	376.53	48.69 *
HARDEE POWER PART. TO ENGY.AUTH.3/98	ECON.-C	(124.0)	0.0	(124.0)	2.166	2.621	(2,685.40)	(3,249.42)	(451.22)*
HARDEE POWER PART. TO ENGY.AUTH.3/98	ECON.-C	124.0	0.0	124.0	2.166	2.725	2,685.40	3,379.35	555.16 *
SUB-TOTAL ECONOMY POWER SALES		94,397.0	0.0	94,397.0	1.552	1.971	1,464,605.75	1,860,333.65	316,582.32
SUB-TOTAL SCHEDULE D POWER SALES-SEPAR.		28,807.0	0.0	28,807.0	1.455	1.692	419,214.51	487,435.76	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.		5,695.0	10.4	5,684.6	1.466	1.466	83,331.85	83,331.85	
SUB-TOTAL SCHEDULE J POWER SALES-JURISD.		5,471.0	0.0	5,471.0	2.397	2.397	131,134.07	131,134.07	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEPAR.		9,252.0	0.0	9,252.0	2.376	3.036	219,844.17	280,923.21	
SUB-TOTAL OTHER D POWER SALES		61,115.0	44,451.0	16,664.0	1.776	1.753	296,016.79	292,154.68	
TOTAL INCLUDING VARIABLE O & M COSTS		204,737.0	44,461.4	160,275.6	1.631	1.956	2,614,147.14	3,135,313.22	316,582.32
LESS VARIABLE O & M COSTS							(157,642.99)		
LESS VARIABLE O & M COSTS - HARDEE							782.77		
LESS TRANSMISSION COSTS SCH. D (SEP.)							(16,711.20)		
LESS TRANSMISSION COSTS SCH. D (OTHER)							(31,859.96)		
PLUS 80% OF ECON. ENERGY SALES PROFITS -							316,582.32		
TOTAL EXCL. VARIABLE O & M COSTS AND INCL. 80% OF ECON. ENERGY SALES PROFITS -		204,737.0	44,461.4	160,275.6	1.700	1.956	2,725,298.08	3,135,313.22	316,582.32
CURRENT MONTH:									
DIFFERENCE -		(20,260.0)	44,461.4	(64,721.4)	(0.096)	(0.084)	(1,314,921.92)	(1,455,686.78)	(116,137.68)
DIFFERENCE % -		(9.0)	0.0	(28.8)	(5.3)	(4.1)	(32.5)	(31.7)	(26.8)
PERIOD TO DATE:									
ACTUAL -		204,737.0	44,461.4	160,275.6	1.700	1.956	2,725,298.08	3,135,313.22	316,582.32
ESTIMATED -		224,997.0	0.0	224,997.0	1.796	2.040	4,040,220.00	4,591,000.00	432,720.00
DIFFERENCE -		(20,260.0)	44,461.4	(64,721.4)	(0.096)	(0.084)	(1,314,921.92)	(1,455,686.78)	(116,137.68)
DIFFERENCE % -		(9.0)	0.0	(28.8)	(5.3)	(4.1)	(32.5)	(31.7)	(26.8)

* NO ECONOMY SALES TO HARDEE POWER PARTNERS IN THE MONTH OF APRIL 1998.

SCHEDULE A7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION PURCH.)
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF APRIL, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) -----CENTS/KWH----- (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6) x (7A)
ESTIMATED:								
VARIOUS	EMER.	3,008.0	0.0	2,036.0	972.0	5.165	5.165	50,200.00
HARDEE POWER PARTNERS	IPP	11,358.0	0.0	0.0	11,358.0	4.064	4.064	461,600.00
ST. CLOUD	PEAKING	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL	-	14,366.0	0.0	2,036.0	12,330.0	4.151	4.151	511,800.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	4,081.0	0.0	0.0	4,081.0	(7.372)	(7.372)	(300,850.58)
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-Jc	4,982.0	0.0	0.0	4,982.0	3.098	3.098	154,327.01
FLA. POWER & LIGHT	SCH.-Ja	457.0	0.0	417.9	39.1	4.251	4.251	1,661.96
FLA. POWER & LIGHT	SCH.-Jc	4,319.0	0.0	0.0	4,319.0	3.769	3.769	162,773.52
ORLANDO	SCH.-Jc	5,195.0	0.0	0.0	5,195.0	3.013	3.013	156,551.01
PECO	OTHER	37,915.0	37,915.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	OTHER	6,536.0	6,536.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO MAR. 1998:								
HARDEE PWR. PART.-NATIVE	IPP	(6,214.0)	0.0	0.0	(6,214.0)	3.978	3.978	(247,171.42)
HARDEE PWR. PART.-NATIVE	IPP	6,214.0	0.0	0.0	6,214.0	4.321	4.321	268,486.43
TOTAL		63,485.0	44,451.0	417.9	18,616.1	1.052	1.052	195,777.93
CURRENT MONTH:								
DIFFERENCE	-	49,119.0	44,451.0	(1,618.1)	6,286.1	(3.099)	(3.099)	(316,022.07)
DIFFERENCE %	-	341.9	0.0	(79.5)	51.0	(74.7)	(74.7)	(61.7)
PERIOD TO DATE:								
ACTUAL	-	63,485.0	44,451.0	417.9	18,616.1	1.052	1.052	195,777.93
ESTIMATED	-	14,366.0	0.0	2,036.0	12,330.0	4.151	4.151	511,800.00
DIFFERENCE	-	49,119.0	44,451.0	(1,618.1)	6,286.1	(3.099)	(3.099)	(316,022.07)
DIFFERENCE %	-	341.9	0.0	(79.5)	51.0	(74.7)	(74.7)	(61.7)

SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF APRIL, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTERRUP-TIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7)(A)
ESTIMATED:								
VARIOUS	COGEN.	38,677.0	0.0	0.0	38,677.0	2.326	2.326	899,600.00
TOTAL	-	38,677.0	0.0	0.0	38,677.0	2.326	2.326	899,600.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	635.0	0.0	0.0	635.0	1.768	1.768	11,228.73
McKAY BAY REFUSE	COGEN.	10,911.0	0.0	0.0	10,911.0	1.569	1.569	171,238.92
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	113.0	0.0	0.0	113.0	1.980	1.980	2,237.53
HILLSBOROUGH COUNTY	COGEN.	19,432.0	0.0	0.0	19,432.0	1.579	1.579	306,755.31
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	102.0	0.0	0.0	102.0	2.110	2.110	2,151.70
FARMLAND HYDRO LP	COGEN.	145.0	0.0	0.0	145.0	2.493	2.493	3,614.68
IMC-AGRICO-S. PIERCE	COGEN.	948.0	0.0	0.0	948.0	2.254	2.254	21,369.29
AUBURNDALE POWER PARTNERS	COGEN.	72.0	0.0	0.0	72.0	1.626	1.626	1,170.57
ORANGE COGENERATION L.P.	COGEN.	7,590.0	0.0	0.0	7,590.0	1.603	1.603	121,633.52
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	6.0	(6.0)	4.248	4.248	(254.88)
SUB-TOTAL FOR APRIL, 1998	-	39,948.0	0.0	6.0	39,942.0	1.605	1.605	641,145.97
ADJUSTMENTS FOR FEB., 1998								
IMC-AGRICO-NICHOLS	COGEN.							
McKAY BAY REFUSE	COGEN.	(9,646.0)	0.0	0.0	(9,646.0)	1.493	1.493	(144,001.21)
MULBERRY PHOSPHATES INC.	COGEN.	9,646.0	0.0	0.0	9,646.0	1.493	1.493	143,998.28
CARGILL RIDGEWOOD	COGEN.							
IMC-AGRICO-NEW WALES	COGEN.							
HILLSBOROUGH COUNTY	COGEN.	(15,479.0)	0.0	0.0	(15,479.0)	1.497	1.497	(231,734.19)
CARGILL MILLPOINT	COGEN.	15,479.0	0.0	0.0	15,479.0	1.497	1.497	231,729.29
CF INDUSTRIES INC.	COGEN.							
FARMLAND HYDRO LP	COGEN.							
IMC-AGRICO-S. PIERCE	COGEN.							
AUBURNDALE POWER PARTNERS	COGEN.							
ORANGE COGENERATION L.P.	COGEN.	(5,037.0)	0.0	0.0	(5,037.0)	1.492	1.492	(75,144.76)
AS AVAILABLE ASSIGNMENT	COGEN.	5,037.0	0.0	0.0	5,037.0	1.492	1.492	75,141.72
ORANGE COGENERATION L.P. 1997 LINE LOSS ADJUSTMENT	COGEN.							(2,810.37)
SUB-TOTAL FOR FEB., 1998 ADJ.	-	0.0	0.0	0.0	0.0	0.000	0.000	(2,821.24)
GRAND TOTAL		39,948.0	0.0	6.0	39,942.0	1.598	1.598	638,324.73
CURRENT MONTH:								
DIFFERENCE	-	1,271.0	0.0	6.0	1,265.0	(0.728)	(0.728)	(261,275.27)
DIFFERENCE %	-	3.3	0.0	0.0	3.3	(31.3)	(31.3)	(29.0)
PERIOD TO DATE:								
ACTUAL		39,948.0	0.0	6.0	39,942.0	1.598	1.598	638,324.73
ESTIMATED		38,677.0	0.0	0.0	38,677.0	2.326	2.326	899,600.00
DIFFERENCE	-	1,271.0	0.0	6.0	1,265.0	(0.728)	(0.728)	(261,275.27)
DIFFERENCE %	-	3.3	0.0	0.0	3.3	(31.3)	(31.3)	(29.0)

SCHEDULE A9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE MONTH OF APRIL, 1998

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACT. COST cents/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3)X(4)	(6) COST IF GENERATED (A) cents/KWH	(6) COST IF GENERATED (B) $	(7) FUEL SAVINGS (6)(B)-(5)
ESTIMATED:							
VARIOUS	ECON.	1,868.0	4.320	80,700.00	5.241	97,900.00	17,200.00
TOTAL	-	1,868.0	4.320	80,700.00	5.241	97,900.00	17,200.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	33.0	2.137	705.05	2.480	818.41	113.36
FLA. PWR. & LIGHT	ECON.-C	278.0	2.949	8,197.48	2.946	8,189.78	(7.70)
CITY OF LAKELAND	ECON.-C	25.0	2.808	702.00	3.141	785.25	83.25
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	34.0	2.623	891.98	3.336	1,134.36	242.38
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	36.0	2.961	1,065.90	3.101	1,116.39	50.49
ORLANDO UTIL. COMM.	ECON.-C	55.0	2.730	1,501.53	3.024	1,663.06	161.53
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	5.0	3.287	164.33	3.773	188.66	24.33
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ADJUSTMENTS TO MARCH, 1998							
FLA. PWR. & LIGHT	ECON.-C	(283.0)	2.640	(7,470.54)	2.748	(7,775.93)	(305.39)
FLA. PWR. & LIGHT	ECON.-C	283.0	2.640	7,470.44	2.748	7,775.93	305.49
TOTAL	-	466.0	2.839	13,228.17	2.982	13,895.91	667.74
CURRENT MONTH:							
DIFFERENCE	-	(1,402.0)	(1.481)	(67,471.83)	(2.259)	(84,004.09)	(16,532.26)
DIFFERENCE %	-	(75.1)	(34.3)	(83.6)	(43.1)	(85.8)	(96.1)
PERIOD TO DATE:							
ACTUAL		466.0	2.839	13,228.17	2.982	13,895.91	667.74
ESTIMATED		1,868.0	4.320	80,700.00	5.241	97,900.00	17,200.00
DIFFERENCE	-	(1,402.0)	(1.481)	(67,471.83)	(2.259)	(84,004.09)	(16,532.26)
DIFFERENCE %	-	(75.1)	(34.3)	(83.6)	(43.1)	(85.8)	(96.1)

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-1)
DOCUMENT NO. 5
PAGE 1 OF 1

Tampa Electric Company

Deferred Revenue Plan $25 Million Base Rate Adjustment
April 1998 Through December 1998

Month	Beginning Balance $	Actual Retail Sales MWH	Projected Revenue $	Ending Balance $
Oct-97	$25,000,000	1,323,633	$1,720,723	$23,279,277
Nov-97	$23,279,277	1,107,991	$1,440,388	$21,838,889
Dec-97	$21,838,889	1,129,167	$1,467,917	$20,370,972
Jan-98	$20,370,972	1,209,576	$1,572,449	$18,798,523
Feb-98	$18,798,523	1,092,763	$1,420,592	$17,377,931
Mar-98	$17,377,931	1,110,059	$1,443,077	$15,934,854
Apr-98	$15,934,854	1,166,092	$1,515,920	$14,418,934
May-98	$14,418,934	1,209,189	$1,571,946	$12,846,988
			0.130	¢/kWh
		Actual Retail Sales		
Jun-98	$12,846,988	1,513,452	$1,981,925	$10,865,063
Jul-98	$10,865,063	1,600,177	$2,095,494	$8,769,569
Aug-98	$8,769,569	1,517,877	$1,987,719	$6,781,850
Sep-98	$6,781,850	1,543,055	$2,020,691	$4,761,159
Oct-98	$4,761,159	1,441,649	$1,887,896	$2,873,263
Nov-98	$2,873,263	1,263,522	$1,654,632	$1,218,631
Dec-98	$1,218,631	1,263,475	$1,654,570	($435,939)
	Retail Average Refund Rate		0.131	¢/kWh

Refund Adjustment For Variations in Line Loss			
Fuel Group	Average Refund	Line Loss Factor	Group Rate ¢/kWh
Group A: RS, GS, TS	0.131	1.0072	0.132
Group A1: SL, OL	0.131	1.0072	0.132
Group B: GSD, GSLD, SBF	0.131	1.0013	0.131
Group C: IS, SBI	0.131	0.9687	0.127

Revisions to the testimony of Karen O. Zwolak – Docket No. 990001

EX 28

Page No.	Line No.	Revision
8	13	Add the word "and" after "("CT")," Replace the comma after "agreement" and replace with a period Strike entire line
	14	
	15	
11	24-25	Strike both lines
12	1-22	Strike lines 1-22
13	5	Strike "$0.43" and replace with "$1.99"

Document KOZ-4 has been deleted from my exhibits

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 28
COMPANY/
WITNESS: Zwolak
DATE: 11-22-99

DOCUMENT NO. 1

EXHIBIT NO. 29
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-2)
FILED 10/01/99

TAMPA ELECTRIC COMPANY

TABLE OF CONTENTS

PAGE NO.	DESCRIPTION	PERIOD
1	Schedule E-1 Cost Recovery Clause Calculation	(JAN.,2000 - DEC.,2000)
2	Schedule E1-A Calculation of Total True-Up	(JAN.,2000 - DEC.,2000)
3	Schedule E-1B Calculation of Estimated True-Up	(JAN.,1999 - DEC.,1999)
4	Schedule E-1B-1 Comparison of Est/ Act vs Original Proj of the Fuel and Pur. Pwr Cost Recovery Fac.	(JAN.,1999 - DEC.,1999)
5	Schedule E-1C GPIF & True-Up Adj. Factors	(JAN.,2000 - DEC.,2000)
6	Schedule E-1D Fuel Adjustment Factor for TOD	(")
7	Schedule E-1E Fuel Recovery Factor-with Line Losses	(")
8	Schedule E-2 Cost Recovery Clause Calculation(By Month)	(")
9-10	Schedule E-3 Generating System Comparative Data	(")
11-22	Schedule E-4 System Net Generation & Fuel Cost	(")
23-24	Schedule E-5 Inventory Analysis	(")
25-26	Schedule E-6 Power Sold	(")
27	Schedule E-7 Purchased Power	(")
28	Schedule E-8 Energy Payment to Qualifying Facilities	(")
29	Schedule E-9 Economy Energy Purchases	(")
30	Schedule E-10 Residential Bill Comparison	(")
31	Schedule E-2 Cost Recovery Clause Calculation	(JAN.,1999 - DEC.,1999)
32-33	Schedule E-3 Generating System Comparative Data	(")
34-35	Schedule E-5 Inventory Analysis	(")
36-37	Schedule E-6 Power Sold	(")
38	Schedule E-7 Purchased Power	(")
39	Schedule E-8 Energy Payment to Qualifying Facilities	(")
40	Schedule E-9 Economy Energy Purchases	(")
41	Schedule H-1 Generating System Comparative Data	(JAN. - DEC., 1997-2000)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 29
COMPANY/
WITNESS: Zavalak
DATE: 11-22-99

SCHEDULE E1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU DECEMBER 2000

	DOLLARS		MWH		cents/KWH
1. Fuel Cost of System Net Generation (E3)	360,441,857		17,943,729		2.00873
2. Nuclear Fuel Disposal Cost	0		0		0.00000
3. Coal Car Investment	0		0		0.00000
4. Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(48,000)		17,943,729	*	(0.00027)
4a. Adjustments to Fuel Cost	0		0		0.00000
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4a)	360,393,857		17,943,729		2.00847
6. Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	37,385,200		1,017,678		3.67358
7. Energy Cost of Sch C,X Economy Purchases (Broker) (E9)	8,484,700		212,054		4.00120
8. Energy Cost of Economy Purchases (Non-Broker) (E9)	0		0		0.00000
9. Energy Cost of Sch. E Economy Purchases (E9)	0		0		0.00000
10. Capacity Cost of Sch. E Economy Purchases (E2)	0		0		0.00000
11. Energy Payments to Qualifying Facilities (E8)	9,225,300		411,909		2.23965
12. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 11)	55,095,200		1,641,641		3.35611
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)			19,585,370		
14. Fuel Cost of Economy Sales (E6)	1,393,300		62,152		2.24176
15. Gain on Economy Sales - 80% (E6)	375,120		62,152	*	0.60355
16. Fuel Cost of Schedule D Sales - Jurisd. (E6)	1,385,700		69,615		1.99052
16a. Fuel Cost of Schedule D Sales - Separated (E6)	295,300		19,153		1.54180
16b. Fuel Cost of Schedule D HPP Sales - Contract (E6)	6,173,000		265,746		2.32289
16c. Fuel Cost of Schedule J Sales - Jurisd. (E6)	0		0		0.00000
17. Fuel Cost of Other D Power Sales	33,850,396		1,317,600		2.56910
18. TOTAL FUEL COST AND GAINS OF POWER SALES	43,472,816		1,734,266		2.50670
19. Net Inadvertant Interchange			0		
19a. Wheeling Rec'd. less Wheeling Delv'd.			0		
19b. Interchange and Wheeling Losses			26,200		
20. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	372,016,241		17,824,904		2.08706
21. Net Unbilled	0	*(a)	NA	(a)	0.00000
22. Company Use	1,001,789	*	48,000		0.00591
23. T & D Losses	17,347,489	*	831,193		0.10237
24. System MWH Sales	372,016,241		16,945,711		2.19534
25. Wholesale MWH Sales	(6,806,819)		(301,707)		2.25610
26. Jurisdictional MWH Sales	365,209,422		16,644,004		2.19424
26a. Jurisdictional Loss Multiplier					1.00068
27. Jurisdictional MWH Sales Adjusted for Line Loss	365,457,764		16,644,004		2.19573
28. True-up **	3,666,883		16,644,004		0.02203
29. Peabody Coal Contract Buy-Out Amort. (Jurisdictionalized)	4,271,199		16,644,004		0.02566
30. Fuel Credit Differential	0		16,644,004		0.00000
31. Total Jurisdictional Fuel Cost (Excl. GPIF)	373,395,846		16,644,004		2.24343
32. Revenue Tax Factor					1.00072
33. Fuel Factor (Excl. GPIF) Adjusted for Taxes	373,664,691		16,644,004		2.24505
34. GPIF * * (Already Adjusted for Taxes)	(276,901)		16,644,004		(0.00166)
35. Fuel Factor Adjusted for Taxes Including GPIF	373,387,790		16,644,004		2.24339
36. Fuel Factor Rounded to Nearest .001 cents per KWH					2.243

(a) Data not available at this time.

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E1-A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2000 THRU DECEMBER 2000

1. ESTIMATED OVER/(UNDER) RECOVERY (SCH. E-1B) January - December 1999 (8 months actual, 4 months estimated)	($11,546,819)
2. FINAL TRUE-UP (April - December 1998) (Per True-Up filed April 1, 1999 and Revised September 29, 1999)	$7,879,936
3. TOTAL OVER/(UNDER) RECOVERY (Lines 1 + 2) To be included in the 12 month projected period January thru December 2000 (Schedule E1, line 28)	($3,666,883)
4. JURISDICTIONAL MWH SALES (Projected January thru December 2000)	16,644,004
5. TRUE-UP FACTOR (Lines 3/4) * (100 cents/1000 KWH)	**($0.022)**

SCHEDULE E-1B

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 4 MONTHS ESTIMATED)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JANUARY 1999 THRU DECEMBER 1999

	ACTUAL								ESTIMATED				TOTAL
	JAN-99	FEB-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99	PERIOD
A 1. FUEL COST OF SYSTEM NET GENERATION	25,576,800	20,861,882	20,668,049	25,471,536	26,935,229	27,572,523	34,615,520	34,678,741	32,066,631	27,873,425	22,816,685	26,877,121	326,014,142
2. FUEL COST OF POWER SOLD *	659,730	409,285	389,382	1,109,126	910,132	1,251,421	1,650,430	1,720,666	1,932,900	1,261,900	792,180	1,087,020	13,174,172
3. FUEL COST OF PURCHASED POWER	1,663,944	1,409,272	2,973,084	7,997,043	5,786,581	6,427,746	7,347,098	11,352,741	2,476,900	1,608,200	1,349,000	839,300	51,230,909
3a. DEMAND & NON-FUEL COST OF PUR. PWR.	0	0	0	0	0	0	0	0	0	0	0	0	0
3b. ENERGY PAYMENTS TO QUALIFIED FACILITIES	643,900	592,142	721,993	933,508	1,157,625	772,850	648,194	711,449	823,500	679,300	640,200	587,600	8,912,261
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0	0	0	0	(15,402)	412,600	243,300	310,000	120,900	1,071,398
5. ADJUSTMENTS TO FUEL COST	(3,863)	(3,412)	(3,605)	(4,206)	(4,442)	(3,798)	(4,313)	(4,507)	(4,000)	(4,000)	(4,000)	(4,000)	(48,146)
(FT. MEADE / WAUCHULA WHEELING) 5a. ADJUSTMENTS TO FUEL COST	(606,674)	(606,801)	(606,863)	(606,864)	(607,036)	(607,277)	(607,579)	(607,751)	(606,674)	(606,674)	(606,674)	(606,673)	(7,283,540)
6. TOTAL FUEL & NET POWER TRANSACTION (Sum of Lines A1 Through A5a)	26,614,377	21,843,798	23,363,276	32,681,891	32,357,825	32,910,623	40,348,490	44,394,605	33,236,057	28,531,651	23,713,031	26,727,228	366,722,852
*INCLUDES ECONOMY SALES PROFITS (80%)													
B 1. JURISDICTIONAL MWH SALES	1,275,517	1,103,597	1,114,374	1,160,503	1,257,285	1,419,058	1,464,514	1,534,220	1,569,571	1,398,242	1,210,130	1,210,554	15,717,565
2. NON-JURISDICTIONAL MWH SALES	13,252	8,300	15,024	39,277	30,041	43,494	59,542	73,444	29,899	18,196	10,500	10,645	351,614
3. TOTAL SALES (Lines B1 + B2)	1,288,769	1,111,897	1,129,398	1,199,780	1,287,326	1,462,552	1,524,056	1,607,664	1,599,470	1,416,438	1,220,630	1,221,199	16,069,179
4. JURISDIC. % OF TOTAL SALES (Line B1/B3)	0.9897173	0.9925353	0.9866973	0.9672632	0.9766640	0.9702616	0.9609319	0.9543163	0.9813069	0.9871537	0.9913979	0.9912832	-
C 1. JURISDICTIONAL FUEL RECOVERY REVENUE (Net of Revenue Taxes)	27,888,414	24,172,488	24,401,298	25,312,420	27,744,949	31,164,870	32,124,318	33,803,899	34,761,971	30,942,721	26,753,737	26,765,729	345,836,814
1a. ADJUSTMENTS TO FUEL REVENUE	0	0	0	0	0	0	0	0	0	0	0	0	0
2. TRUE-UP PROVISION	438,426	438,426	438,426	438,426	438,426	438,426	438,426	438,426	438,426	438,426	438,426	438,426	5,261,112
2a. INCENTIVE PROVISION	15,679	15,679	15,679	15,679	15,679	15,679	15,679	15,679	15,679	15,679	15,679	15,676	188,145
2b. OTHER	0	0	0	0	0	0	0	0	0	0	0	0	0
3. FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2b)	28,342,519	24,626,593	24,855,403	25,766,525	28,199,054	31,618,975	32,578,423	34,258,004	35,216,076	31,396,826	27,207,842	27,219,831	351,286,071
4. TOTAL FUEL & NET PWR. TRANS. (Line A6)	26,614,377	21,843,798	23,363,276	32,681,891	32,357,825	32,910,623	40,348,490	44,394,605	33,236,057	28,531,651	23,713,031	26,727,228	366,722,852
5. JURISDIC. TOTAL FUEL & NET PWR.TRANS. (Line A6 x Line B4)	26,340,711	21,680,740	23,052,481	31,611,990	31,602,723	31,931,911	38,772,149	42,366,495	32,614,772	28,165,125	23,509,049	26,494,252	358,142,398
5a. JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	-
5b. LINE 5 X LINE 5a	26,358,623	21,695,483	23,068,157	31,633,486	31,624,213	31,953,625	38,798,514	42,395,304	32,636,950	28,184,277	23,525,035	26,512,268	358,385,935
5c. PEABODY COAL CONTRACT BUY-OUT AMORT.	406,337	403,806	404,275	398,744	396,213	393,682	391,151	388,621	386,090	383,559	381,028	378,497	4,712,003
5d. PEABODY JURISDICTIONALIZED (LINE 5c X LINE B4)	402,159	400,792	398,897	385,690	386,967	381,975	375,869	370,867	378,873	378,632	377,750	375,198	4,613,669
5e. FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS. INCL. PEABODY & FUEL CREDIT DIFF.	26,760,782	22,096,275	23,467,054	32,019,176	32,011,180	32,335,600	39,174,383	42,766,171	33,015,823	28,562,909	23,902,785	26,887,466	362,999,604
7. OVER/(UNDER) RECOVERY	1,581,737	2,530,318	1,388,349	(6,252,651)	(3,812,126)	(716,625)	(6,595,960)	(8,508,167)	2,200,253	2,833,917	3,305,057	332,365	(11,713,533)
8. INTEREST PROVISION	55,536	62,005	68,723	57,093	35,188	25,133	8,528	(25,892)	(43,608)	(35,406)	(23,430)	(17,156)	166,714
9. TOTAL ESTIMATED TRUE-UP FOR THE PERIOD													(11,546,819)

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JAN.,1999 THRU DEC.,1999

SCHEDULE E-1B-1

	DOLLARS				MWH				cents/KWH			
	ACTUAL/ ESTIMATED JAN.-DEC. 99	ESTIMATED ORIGINAL JAN.-DEC. 99	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL/ ESTIMATED JAN.-DEC. 99	ESTIMATED ORIGINAL JAN.-DEC. 99	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL/ ESTIMATED JAN.-DEC. 99	ESTIMATED ORIGINAL JAN.-DEC. 99	DIFFERENCE AMOUNT	DIFFERENCE %
1. Fuel Cost of System Net Generation (E3)	326,014,142	370,767,451	(44,753,309)	(12.1)	15,832,134	17,949,322	(2,117,188)	(11.8)	2.05919	2.06563	(0.00644)	(0.3)
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
3. Coal Car Investment	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
4. Adjustments to Fuel Cost (FL Meade/Wauch. Wheeling)	(48,146)	(36,000)	(12,146)	33.7	15,832,134 *	17,949,322 *	(2,117,188)	(11.8)	(0.00030)	(0.00020)	(0.00010)	50.0
4a. Adjustments to Fuel Cost	(7,283,540)	0	(7,283,540)	0.0	15,832,134 *	17,949,322 *	(2,117,188)	(11.8)	(0.04600)	0.00000	(0.04600)	0.0
5. TOTAL COST OF GENERATED POWER	318,682,456	370,731,451	(52,048,995)	(14.0)	15,832,134	17,949,322	(2,117,188)	(11.8)	2.01288	2.06543	(0.05255)	(2.5)
6. Fuel Cost of Purchased Power - (Exclusive of Econ) (E7)	51,230,909	19,610,500	31,620,409	161.2	1,413,008	537,382	875,626	162.9	3.62566	3.64927	(0.02361)	(0.6)
7. Energy Cost of Sch C,X Economy Purchases (Broker) (E	1,071,398	1,103,200	(31,802)	(2.9)	26,023	24,265	1,758	7.2	4.11712	4.54647	(0.42935)	(9.4)
8. Energy Cost of Other Econ Purch (Non-Broker) (E9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
9. Energy Cost of Sch. E Econ Purchases (E9)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
11. Energy Payments to Qualifying Facilities (E8)	8,912,261	8,323,300	588,961	7.1	426,921	415,188	11,733	2.8	2.08757	2.00471	0.08286	4.1
12. TOTAL COST OF PURCHASED POWER	61,214,568	29,037,000	32,177,568	110.8	1,865,952	976,835	889,117	91.0	3.28061	2.97256	0.30805	10.4
13. TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					17,698,086	18,926,157	(1,228,071)	(6.5)				
14. Fuel Cost of Economy Sales (E6)	1,634,534	22,131,600	(20,497,066)	(92.6)	85,322	1,179,676	(1,094,354)	(92.8)	1.91572	1.87607	0.03965	2.1
15. Gain on Economy Sales - 80% (E6)	423,710	5,088,960	(4,665,250)	(91.7)	85,322 *	1,179,676 *	(1,094,354)	(92.8)	0.49660	0.43139	0.06521	15.1
16. Fuel Cost of Schedule D Sales - Jurisd. (E6)	965,176	1,359,900	(394,724)	(29.0)	65,354	68,424	(3,070)	(4.5)	1.47684	1.98746	(0.51062)	(25.7)
16a. Fuel Cost of Schedule D Sales - Separated (E6)	3,829,330	4,310,300	(480,970)	(11.2)	228,779	259,111	(30,332)	(11.7)	1.67381	1.66350	0.01031	0.6
16b. Fuel Cost of Schedule D HPP Sales - Contract (E6)	5,814,615	6,041,700	(227,085)	(3.8)	267,615	255,600	12,015	4.7	2.17275	2.36373	(0.19098)	(8.1)
16c. Fuel Cost of Schedule J Sales - Jurisd. (E6)	726,785	559,200	167,585	30.0	24,349	23,420	929	4.0	2.98487	2.38770	0.59717	25.0
17. Fuel Cost of Other D Power Sales (E6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17a. Fuel Cost of Other Sales (E6)	0	0	0	0.0	0	0	0	0.0	0.00000	0.00000	0.00000	0.0
17b. Transmission Cost for Various Sales (E6)	(219,978)	0				0						
18. TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14 thru 17b)	13,174,172	39,491,660	(26,317,488)	(66.6)	671,419	1,786,231	(1,114,812)	(62.4)	1.96214	2.21089	(0.24875)	(11.3)
19. Net Inadvertant Interchange					851	0	851	0.0				
19a. Wheeling Rec'd. Less Wheeling Delv'd.					(2,172)	0	(2,172)	0.0				
19b. Interchange and Wheeling Losses					16,936	26,800	(9,864)	(36.8)				
20. TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 +19 + 19a + 19b)	366,722,852	360,276,791	6,446,061	1.8	17,008,409	17,113,126	(104,717)	(0.6)	2.15613	2.10527	0.05086	2.4
21. Net Unbilled	2,821,641 *	0 *	2,821,641	0.0	130,866	0	130,866	0.0	0.01659	0.00000	0.01659	0.0
22. Company Use	1,042,101 *	947,372 *	94,729	10.0	48,332	45,000	3,332	7.4	0.00649	0.00583	0.00066	11.3
23. T & D Losses	16,387,289 *	17,162,519 *	(775,230)	(4.5)	760,032	815,217	(55,185)	(6.8)	0.10196	0.10560	(0.00362)	(3.4)
24. System KWH Sales	366,722,852	360,276,791	6,446,061	1.8	16,069,179	16,252,909	(183,730)	(1.1)	2.28215	2.21669	0.06546	3.0
25. Wholesale KWH Sales	(8,580,454)	(5,925,475)	(2,654,979)	44.8	(351,614)	(262,806)	(88,808)	33.8	2.44030	2.25470	0.18560	8.2
26. Jurisdictional KWH Sales	358,142,398	354,351,316	3,791,082	1.1	15,717,565	15,990,103	(272,538)	(1.7)	2.27861	2.21607	0.06254	2.8
26a. Jurisdictional Loss Multiplier									1.00068	1.00068	0.00000	0.0
27. Jurisdictional KWH Sales Adjusted for Line Losses	358,385,935	354,592,275	3,793,660	1.1	15,717,565	15,990,103	(272,538)	(1.7)	2.28016	2.21757	0.06259	2.8
28. True-up **	(13,141,049)	(5,261,113)	(7,879,936)	149.8	15,717,565	15,990,103	(272,538)	(1.7)	(0.08361)	(0.03290)	(0.05071)	154.1
29a. Peabody Coal Contract Buy-out Amort. (Jurisd.)	4,613,669	4,635,960	(22,291)	(0.5)	15,717,565	15,990,103	(272,538)	(1.7)	0.02935	0.02899	0.00036	1.2
29b. Adjustment	0	0	0	0.0	15,717,565	15,990,103	(272,538)	(1.7)	0.00000	0.00000	0.00000	0.0
30. Total Jurisdictional Fuel Cost (Excl. GPIF)	349,856,555	353,967,122	(4,108,567)	(1.2)	15,717,565	15,990,103	(272,538)	(1.7)	2.22591	2.21366	0.01225	0.6
31. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0
32. Fuel Factor (Excl. GPIF) Adjusted for Taxes	350,110,453	354,221,978	(4,111,525)	(1.2)	15,717,565	15,990,103	(272,538)	(1.7)	2.22751	2.21525	0.01226	0.6
33. GPIF ** (($276,702) - Not Adjusted for Taxes)	(276,901)	(188,281)	(88,620)	47.1	15,717,565	15,990,103	(272,538)	(1.7)	(0.00176)	(0.00118)	(0.00058)	49.2
34. Fuel Factor Adjusted for Taxes Including GPIF	349,833,552	354,033,697	(4,200,145)	(1.2)	15,717,565	15,990,103	(272,538)	(1.7)	2.22575	2.21407	0.01168	0.5
35. Fuel Factor Rounded to Nearest .001 cents per KWH									2.226	2.214	0.01200	0.5

* Included For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
Note: Amounts Included in Estimated/Actual column represent five months actual and four months revised estimates.
Amounts Included in the Estimated Original column represent the sum of the projected period filed in Jan. 1998 (Apr.-Sept. 98) and in June 1998 (Oct.-Dec. 98).

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2000 THRU DECEMBER 2000

1. TOTAL AMOUNT OF ADJUSTMENTS:

   A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)
   (JANUARY 2000 THRU DECEMBER 2000) ($276,901)

   B. TRUE-UP OVER / (UNDER) RECOVERED
   (JANUARY 1999 THRU DECEMBER 1999) ($3,666,883)

2. TOTAL SALES
   (JANUARY 2000 THRU DECEMBER 2000) 16,644,004 MWH

3. ADJUSTMENT FACTORS:

   A. GENERATING PERFORMANCE INCENTIVE FACTOR (0.0017) Cents/KWH

   B. TRUE-UP FACTOR 0.0220 Cents/KWH

SCHEDULE E-1D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY
PROJECTION FOR THE PERIOD
JANUARY 2000 THRU DECEMBER 2000

1. COST RATIO:

$$\frac{2.923 \text{ ON-PEAK}}{1.812 \text{ OFF-PEAK}} = 1.6131$$

2. SALES/GENERATION:

30.28 % ON-PEAK 69.72 % OFF-PEAK

3. FORMULA:

X = ON-PEAK Y = OFF-PEAK

0.3028 * 1.6131 Y + 0.6972 Y = 2.2434 INCLUDES TAX @ 1.00072
1.1856 Y = 2.2434
Y = 1.8922

X = 1.6131 Y
X = 1.6131 * 1.8922
X = 3.0523

	ON-PEAK	OFF-PEAK
4. FUEL COST (cents/KWH)	3.0523	1.8922
5. FUEL FACTOR (cents/KWH NEAREST .000)	**3.052**	**1.892**

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2000 THRU DECEMBER 2000

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS,GS,TS		2.243	1.0071	2.259
A1*	SL-2, OL-1&3		2.243	N/A	2.080
B	GSD,GSLD,SBF		2.243	1.0016	2.247
C	IS-1&3,SBI-1&3		2.243	0.9681	2.171
D	N/A		N/A	N/A	N/A
A	RST,GST	ON-PEAK	3.052	1.0071	3.074
		OFF-PEAK	1.892	1.0071	1.905
A1	SL-2, OL-1&3	ON-PEAK	N/A	N/A	N/A
		OFF-PEAK	N/A	N/A	N/A
B	GSDT,EV-X,GSLDT, SBFT	ON-PEAK	3.052	1.0016	3.057
		OFF-PEAK	1.892	1.0016	1.895
C	IST-1&3,SBIT-1&3	ON-PEAK	3.052	0.9681	2.955
		OFF-PEAK	1.892	0.9681	1.832
D	N/A	ON-PEAK	N/A	N/A	N/A
		OFF-PEAK	N/A	N/A	N/A

* GROUP A1 IS BASED ON GROUP A, 15% OF ON-PEAK AND 85% OF OFF-PEAK.

SCHEDULE E2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JANUARY 2000 THRU DECEMBER 2000

LINE NUMBER		(a) Jan-00	(b) Feb-00	(c) Mar-00	(d) Apr-00	(e) May-00	(f) Jun-00	(g) ESTIMATED Jul-00	(h) Aug-00	(i) Sep-00	(j) Oct-00	(k) Nov-00	(l) Dec-00	TOTAL PERIOD	LINE NUMBER
1	FUEL COST OF SYSTEM NET GENERATION	28,107,340	25,441,706	27,216,137	27,016,433	30,897,488	32,987,477	35,095,853	35,013,336	32,268,290	31,144,334	26,661,930	28,771,531	360,441,857	1
1a	NUCLEAR FUEL DISPOSAL	0	0	0	0	0	0	0	0	0	0	0	0	0	1a
2	FUEL COST OF POWER SOLD *	3,349,833	3,117,853	3,521,473	3,826,573	3,792,413	3,801,473	4,148,593	3,918,293	4,067,153	3,571,613	3,215,353	3,342,593	43,472,816	2
3	FUEL COST OF PURCHASED POWER	1,496,900	1,323,100	1,646,700	2,391,900	4,640,100	5,230,100	6,387,500	6,122,900	4,894,000	1,354,400	891,500	1,006,100	37,385,200	3
3a	DEMAND & NON FUEL COST OF PUR POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	3a
3b	QUALIFYING FACILITIES	569,300	533,600	588,800	756,500	661,500	843,200	974,800	960,800	888,400	854,500	734,600	659,500	9,225,300	3b
4	ENERGY COST OF ECONOMY PURCHASES	259,400	173,700	386,100	538,500	1,289,900	753,800	1,022,800	1,221,600	898,800	1,007,800	764,500	165,800	8,484,700	4
4a	ADJUSTMENTS TO FUEL COSTS (FT. MEADE / WAUCHULA WHEELING)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(48,000)	4a
4b	ADJUSTMENTS TO FUEL COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0	4b
5	TOTAL FUEL & NET POWER TRANSACTION (SUM OF LINES 1 THRU 4b)	27,079,307	24,350,455	26,314,264	27,072,760	33,692,575	36,009,104	39,328,360	39,396,143	34,898,337	30,785,421	25,833,177	27,256,336	372,018,241	5
6	JURISDICTIONAL KWH SOLD (MWH)	1,340,065	1,212,891	1,195,727	1,217,471	1,344,317	1,523,259	1,608,621	1,582,440	1,622,106	1,451,333	1,272,763	1,273,009	16,644,004	6
6a	JURISDICTIONAL % OF TOTAL SALES	0.9905877	0.9924467	0.9927412	0.9874143	0.9772118	0.9720582	0.9705848	0.9705774	0.9798190	0.9835312	0.9901111	0.9899851	-	6a
6b	JURISDIC. TOT. FUEL & NET PWR. TRANS. (LINE 5 X LINE 6a)	26,824,428	24,166,529	26,123,254	26,732,030	32,924,782	35,003,305	38,171,508	38,237,006	34,187,074	30,278,422	25,577,715	26,983,389	365,209,422	6b
7	JURISDICTIONAL LOSS MULTIPLIER	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	-	7
7a	LINE 6b x LINE 7	26,842,669	24,182,962	26,141,018	26,750,208	32,947,171	35,027,107	38,197,485	38,263,007	34,210,321	30,299,011	25,595,108	27,001,718	365,457,765	7a
7b	PEABODY COAL CONTRACT BUY-OUT AMORT.	375,968	373,435	370,904	368,373	365,842	363,311	360,780	358,249	355,718	353,187	350,656	348,125	4,344,548	7b
7c	PEABODY JURISDICTIONALIZED (LINE 7b x LINE 6a)	372,427	370,614	368,212	363,737	357,505	353,183	350,168	347,708	348,468	347,370	347,188	344,639	4,271,199	7c
7d	FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0	7d
8	JURISDIC. TOT. FUEL & NET PWR. TRANS. INCL PEABODY AND FUEL CREDIT (LINE 7a + 7c + 7d)	27,215,096	24,553,576	26,509,230	27,113,945	33,304,676	35,380,270	38,547,633	38,610,715	34,558,789	30,646,381	25,942,296	27,346,357	369,728,964	8
9	COST PER KWH SOLD (cents/KWH)	2.0309	2.0244	2.2170	2.2271	2.4774	2.3227	2.3963	2.4399	2.1305	2.1116	2.0383	2.1482	2.2214	9
10	TRUE UP ** (cents/KWH)	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	0.0220	10
11	TOTAL (LINES 9+10)(cents/KWH)	2.0529	2.0464	2.2390	2.2491	2.4994	2.3447	2.4183	2.4619	2.1525	2.1336	2.0603	2.1702	2.2434	11
12	REVENUE TAX FACTOR	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	12
13	RECOVERY FAC. ADJ. FOR TAXES (c/KWH) (EXCL. GPIF)	2.0544	2.0479	2.2406	2.2507	2.5012	2.3464	2.4200	2.4637	2.1540	2.1351	2.0618	2.1718	2.2450	13
14	GPIF ** (cents/KWH) (ALREADY ADJUSTED FOR TAXES)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	(0.0017)	14
15	TOTAL RECOVERY FACTOR (LINES 13+14)	2.0527	2.0462	2.2389	2.2490	2.4995	2.3447	2.4183	2.4620	2.1523	2.1334	2.0601	2.1701	2.2433	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 cents/KWH	2.053	2.046	2.239	2.249	2.500	2.345	2.418	2.462	2.152	2.133	2.060	2.170	2.243	16

* INCLUDES ECONOMY SALES PROFITS (80%)
** BASED ON JURISDICTIONAL SALES ONLY

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU JUNE 2000

		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00
	FUEL COST OF SYSTEM NET GENERATION ($)						
1	HEAVY OIL	85,094	81,553	266,304	1,082,176	1,101,496	1,632,199
2	LIGHT OIL	530,656	475,767	544,612	697,604	319,188	655,070
3	COAL	27,491,590	24,884,388	26,405,221	25,236,653	29,276,804	30,700,208
4	NATURAL GAS	0	0	0	0	0	0
5	NUCLEAR	0	0	0	0	0	0
6	OTHER	0	0	0	0	0	0
7	TOTAL ($)	28,107,340	25,441,708	27,216,137	27,016,433	30,697,488	32,987,477
	SYSTEM NET GENERATION (MWH)						
8	HEAVY OIL	2,017	1,938	6,305	23,288	21,819	35,715
9	LIGHT OIL	14,843	13,583	15,246	17,439	8,678	16,946
10	COAL	1,389,657	1,268,064	1,343,230	1,285,652	1,516,760	1,576,366
11	NATURAL GAS	0	0	0	0	0	0
12	NUCLEAR	0	0	0	0	0	0
13	OTHER	0	0	0	0	0	0
14	TOTAL (MWH)	1,406,517	1,283,585	1,364,781	1,326,379	1,547,257	1,629,027
	UNITS OF FUEL BURNED						
15	HEAVY OIL (BBL)	5,084	4,886	16,034	64,547	65,096	93,846
16	LIGHT OIL (BBL)	22,397	20,181	23,219	29,535	13,444	28,059
17	COAL (TON)	630,429	574,173	610,428	580,814	678,440	715,512
18	NATURAL GAS (MCF)	0	0	0	0	0	0
19	NUCLEAR (MMBTU)	0	0	0	0	0	0
20	OTHER	0	0	0	0	0	0
	BTUS BURNED (MMBTU)						
21	HEAVY OIL	32,138	30,886	101,356	408,001	411,467	593,206
22	LIGHT OIL	130,160	117,072	134,876	171,477	77,834	162,775
23	COAL	14,452,965	13,177,684	13,970,005	13,286,563	15,551,087	16,411,398
24	NATURAL GAS	0	0	0	0	0	0
25	NUCLEAR	0	0	0	0	0	0
26	OTHER	0	0	0	0	0	0
27	TOTAL (MMBTU)	14,615,263	13,325,642	14,206,237	13,866,041	16,040,388	17,167,379
	GENERATION MIX (% MWH)						
28	HEAVY OIL	0.14	0.15	0.46	1.76	1.41	2.19
29	LIGHT OIL	1.06	1.06	1.12	1.31	0.56	1.04
30	COAL	98.80	98.79	98.42	96.93	98.03	96.77
31	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
32	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST PER UNIT						
35	HEAVY OIL ($/BBL)	16.74	16.69	16.61	16.77	16.92	17.39
36	LIGHT OIL ($/BBL)	23.69	23.57	23.46	23.62	23.74	23.35
37	COAL ($/TON)	43.61	43.34	43.26	43.45	43.15	42.91
38	NATURAL GAS ($/MCF	0.00	0.00	0.00	0.00	0.00	0.00
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)						
41	HEAVY OIL	2.65	2.64	2.63	2.65	2.68	2.75
42	LIGHT OIL	4.08	4.06	4.04	4.07	4.10	4.02
43	COAL	1.90	1.89	1.89	1.90	1.88	1.87
44	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
45	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL ($/MMBTU)	1.92	1.91	1.92	1.95	1.91	1.92
	BTU BURNED PER KWH (BTU/KWH)						
48	HEAVY OIL	15,934	15,937	16,075	17,520	18,858	16,609
49	LIGHT OIL	8,769	8,619	8,847	9,833	8,969	9,606
50	COAL	10,400	10,392	10,400	10,334	10,253	10,411
51	NATURAL GAS	0	0	0	0	0	0
52	NUCLEAR	0	0	0	0	0	0
53	OTHER	0	0	0	0	0	0
54	TOTAL (BTU/KWH)	10,391	10,382	10,409	10,454	10,367	10,538
	GENERATED FUEL COST PER KWH (cents/KWH)						
55	HEAVY OIL	4.22	4.21	4.22	4.65	5.05	4.57
56	LIGHT OIL	3.58	3.50	3.57	4.00	3.68	3.87
57	COAL	1.98	1.96	1.97	1.96	1.93	1.95
58	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
59	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL (cents/KWH)	2.00	1.98	1.99	2.04	1.98	2.02

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JULY 2000 THRU DECEMBER 2000

		Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	1,819,743	1,667,726	783,569	476,368	249,237	78,871	9,324,336
2	LIGHT OIL	811,400	703,640	592,246	1,125,337	932,361	720,738	8,108,619
3	COAL	32,464,710	32,641,970	30,912,475	29,027,166	25,277,862	27,882,579	342,201,626
4	NATURAL GAS	0	0	0	515,463	202,470	89,343	807,276
5	NUCLEAR	0	0	0	0	0	0	0
6	OTHER	0	0	0	0	0	0	0
7	TOTAL ($)	35,095,853	35,013,336	32,288,290	31,144,334	26,661,930	28,771,531	360,441,857
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	40,154	36,342	19,824	12,427	13,086	1,960	214,875
9	LIGHT OIL	19,640	17,853	15,621	29,229	22,701	19,075	210,854
10	COAL	1,654,430	1,663,069	1,584,711	1,484,000	1,312,337	1,419,132	17,497,408
11	NATURAL GAS	0	0	0	13,581	4,948	2,063	20,592
12	NUCLEAR	0	0	0	0	0	0	0
13	OTHER	0	0	0	0	0	0	0
14	TOTAL (MWH)	1,714,224	1,717,264	1,620,156	1,539,237	1,353,072	1,442,230	17,943,729
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	104,875	97,134	43,935	25,211	13,498	4,204	538,350
16	LIGHT OIL (BBL)	34,887	29,851	24,434	24,210	16,219	22,574	289,010
17	COAL (TON)	755,278	759,097	717,669	668,767	585,729	643,657	7,919,993
18	NATURAL GAS (MCF)	0	0	0	191,900	71,600	30,000	293,500
19	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20	OTHER	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)							
21	HEAVY OIL	662,910	613,981	277,705	159,357	85,329	26,577	3,402,913
22	LIGHT OIL	202,426	173,380	141,449	257,092	215,213	168,902	1,952,656
23	COAL	17,327,696	17,413,389	16,470,603	15,376,914	13,490,768	14,725,382	181,654,454
24	NATURAL GAS	0	0	0	197,630	73,714	30,869	302,213
25	NUCLEAR	0	0	0	0	0	0	0
26	OTHER	0	0	0	0	0	0	0
27	TOTAL (MMBTU)	18,193,032	18,200,750	16,889,757	15,990,993	13,865,024	14,951,730	187,312,236
	GENERATION MIX (% MWH)							
28	HEAVY OIL	2.34	2.12	1.22	0.81	0.97	0.14	1.20
29	LIGHT OIL	1.15	1.04	0.96	1.90	1.68	1.32	1.18
30	COAL	96.51	96.84	97.82	96.41	96.98	98.40	97.51
31	NATURAL GAS	0.00	0.00	0.00	0.88	0.37	0.14	0.11
32	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST PER UNIT							
35	HEAVY OIL ($/BBL)	17.35	17.17	17.83	18.90	18.46	18.76	17.32
36	LIGHT OIL ($/BBL)	23.26	23.57	24.24	46.48	57.49	31.93	28.06
37	COAL ($/TON)	42.98	43.00	43.07	43.40	43.16	43.32	43.21
38	NATURAL GAS ($/MCF	0.00	0.00	0.00	2.69	2.83	2.98	2.75
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	2.75	2.72	2.82	2.99	2.92	2.97	2.74
42	LIGHT OIL	4.01	4.06	4.19	4.38	4.33	4.27	4.15
43	COAL	1.87	1.87	1.88	1.89	1.87	1.89	1.88
44	NATURAL GAS	0.00	0.00	0.00	2.61	2.75	2.89	2.67
45	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL ($/MMBTU)	1.93	1.92	1.91	1.95	1.92	1.92	1.92
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	16,509	16,895	14,009	12,823	6,521	13,560	15,837
49	LIGHT OIL	10,307	9,712	9,055	8,796	9,480	8,855	9,261
50	COAL	10,474	10,471	10,393	10,362	10,280	10,376	10,382
51	NATURAL GAS	0	0	0	14,552	14,898	14,963	14,676
52	NUCLEAR	0	0	0	0	0	0	0
53	OTHER	0	0	0	0	0	0	0
54	TOTAL (BTU/KWH)	10,613	10,599	10,425	10,389	10,247	10,367	10,439
	GENERATED FUEL COST PER KWH (cents/KWH)							
55	HEAVY OIL	4.53	4.59	3.95	3.83	1.90	4.02	4.34
56	LIGHT OIL	4.13	3.94	3.79	3.85	4.11	3.78	3.85
57	COAL	1.96	1.96	1.95	1.96	1.93	1.96	1.96
58	NATURAL GAS	0.00	0.00	0.00	3.80	4.09	4.33	3.92
59	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL (cents/KWH)	2.05	2.04	1.99	2.02	1.97	1.99	2.01

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST

TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD/MONTH OF: JANUARY 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	32	319	1.3	96.0	99.7	16,232	HVY OIL	819	6,322,344	5,178.0	13,708	4.30	16.74
2	H.P.#2	32	300	1.3	93.0	93.8	16,203	HVY OIL	769	6,321,196	4,861.0	12,871	4.29	16.74
3	H.P.#3	32	319	1.3	93.0	99.7	15,950	HVY OIL	805	6,320,497	5,088.0	13,474	4.22	16.74
4	H.P.#4	41	440	1.4	93.0	97.6	15,718	HVY OIL	1,094	6,321,755	6,916.0	18,311	4.16	16.74
5	H.P.#5	67	639	1.3	83.9	95.4	15,798	HVY OIL	1,597	6,321,227	10,095.0	26,730	4.18	16.74
6	H.P. STATION	204	2,017	1.3	90.5	96.9	15,934	HVY OIL	5,084	6,321,400	32,138.0	85,094	4.22	16.74
7	GAN.#1	114	22,260	26.2	80.1	44.4	12,413	COAL	11,316	24,417,462	276,308.0	478,888	2.15	42.32
8	GAN.#2	113	20,033	23.8	79.6	39.4	13,237	COAL	10,732	24,708,069	265,167.0	454,173	2.27	42.32
9	GAN.#3	155	33,948	29.4	86.0	50.1	12,264	COAL	20,974	19,850,243	416,339.0	887,610	2.61	42.32
10	GAN.#4	189	36,875	26.2	78.8	43.1	12,320	COAL	22,887	19,849,565	454,297.0	968,567	2.63	42.32
11	GAN.#5	242	75,304	41.8	79.8	46.7	10,578	COAL	32,526	24,491,146	796,599.0	1,376,485	1.83	42.32
12	GAN.#6	392	119,596	41.0	76.6	49.3	10,586	COAL	51,793	24,445,234	1,266,092.0	2,191,855	1.83	42.32
13	GANNON STA.	1,205	308,016	34.4	79.4	46.8	11,281	COAL	150,228	23,130,189	3,474,802.0	6,357,578	2.06	42.32
14	B.B.#1	426	237,167	74.8	82.9	81.8	10,031	COAL	104,381	22,792,807	2,379,136.0	4,336,389	1.83	41.54
15	B.B.#2	426	250,081	78.9	84.8	85.5	10,063	COAL	110,042	22,870,204	2,516,683.0	4,571,569	1.83	41.54
16	B.B.#3	443	211,445	64.2	80.9	70.8	10,201	COAL	93,656	23,030,473	2,156,942.0	3,890,831	1.84	41.54
17	B.B. 1 - 3	1,295	698,693	72.5	82.8	79.3	10,094	COAL	308,079	22,892,703	7,052,761.0	12,798,789	1.83	41.54
18	B.B.#4	447	255,907	76.9	86.0	82.7	9,942	COAL	111,622	22,794,216	2,544,336.0	5,814,665	2.27	52.09
19	B.B. STA.	1,742	954,600	73.7	83.7	80.2	10,054	COAL	419,701	22,866,510	9,597,097.0	18,613,454	1.95	44.35
20	PHILLIPS #1 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
21	PHILLIPS #2 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
22	SEB-PHILLIPS TOTAL	34	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
23	POLK COAL	250	127,041	68.3	-	-	10,871	COAL	60,500	22,827,537	1,381,066.0	2,520,558	1.98	41.66
24	POLK OIL	250	14,116	7.6	-	-	8,400	LGT OIL	20,400	5,812,647	118,578.0	484,625	3.43	23.76
25	POLK TOTAL	250	141,157	75.9	88.6	92.1	10,624	-	-	-	1,499,644.0	3,005,183	2.13	-
26	GAN.C.T.#1	17	60	0.5	64.9	88.2	16,117	LGT OIL	167	5,790,419	967.0	3,838	6.40	22.98
27	B.B.C.T.#1	17	61	0.5	64.9	89.7	15,852	LGT OIL	167	5,790,419	967.0	3,850	6.31	23.05
28	B.B.C.T.#2	80	302	0.5	69.1	94.4	15,947	LGT OIL	830	5,802,410	4,816.0	19,137	6.34	23.06
29	B.B.C.T.#3	80	304	0.5	69.1	95.0	15,895	LGT OIL	833	5,800,720	4,832.0	19,206	6.32	23.06
30	C.T. TOTAL	194	727	0.5	68.4	93.7	15,931	LGT OIL	1,997	5,799,700	11,582.0	46,031	6.33	23.05
31	TOT COAL (GN,BB,POLK)	3,197	1,389,657	58.4	75.5	-	10,400	COAL	630,429	22,925,603	14,452,965.0	27,491,590	1.98	43.61
32	SYSTEM	3,629	1,406,517	52.1	75.3	76.0	10,391	-	-	-	14,615,263.0	28,107,340	2.00	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: FEBRUARY 2000

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1 H.P.#1	32	331	1.5	96.0	94.0	16,196	HVY OIL	848	6,321,934	5,361.0	14,154	4.28	16.69
2 H.P.#2	32	308	1.4	93.1	96.3	16,214	HVY OIL	790	6,321,519	4,994.0	13,186	4.28	16.69
3 H.P.#3	32	155	0.7	45.0	96.9	15,935	HVY OIL	391	6,317,136	2,470.0	6,526	4.21	16.69
4 H.P.#4	41	474	1.7	93.1	96.3	15,719	HVY OIL	1,179	6,319,763	7,451.0	19,679	4.15	16.69
5 H.P.#5	67	670	1.4	83.9	90.9	15,836	HVY OIL	1,678	6,323,004	10,610.0	28,008	4.18	16.69
6 H.P. STATION	204	1,938	1.4	83.0	94.0	15,937	HVY OIL	4,886	6,321,326	30,886.0	81,553	4.21	16.69
7 GAN.#1	114	20,472	25.8	80.3	43.7	12,442	COAL	10,435	24,410,254	254,721.0	433,697	2.12	41.58
8 GAN.#2	113	18,525	23.6	79.5	39.0	13,265	COAL	9,996	24,582,633	245,728.0	415,643	2.24	41.58
9 GAN.#3	155	20,664	19.2	56.5	49.4	12,297	COAL	12,802	19,849,164	254,109.0	532,319	2.58	41.58
10 GAN.#4	189	33,440	25.4	78.7	42.2	12,357	COAL	20,818	19,849,457	413,226.0	865,632	2.59	41.58
11 GAN.#5	242	67,630	40.2	79.9	44.9	10,614	COAL	29,338	24,467,210	717,819.0	1,219,902	1.80	41.58
12 GAN.#6	392	107,904	39.5	76.6	47.5	10,624	COAL	46,963	24,409,471	1,146,342.0	1,952,766	1.81	41.58
13 GANNON STA.	1,205	268,635	32.0	75.6	45.3	11,286	COAL	130,352	23,259,674	3,031,945.0	5,420,159	2.02	41.58
14 B.B.#1	426	220,790	74.5	82.9	81.4	10,026	COAL	97,121	22,792,970	2,213,676.0	4,028,976	1.82	41.48
15 B.B.#2	426	231,269	78.0	84.8	84.4	10,065	COAL	101,783	22,870,126	2,327,790.0	4,222,375	1.83	41.48
16 B.B.#3	443	192,868	62.6	80.9	69.1	10,210	COAL	85,505	23,030,302	1,969,206.0	3,547,097	1.84	41.48
17 B.B. 1 - 3	1,295	644,927	71.6	82.8	78.2	10,095	COAL	284,409	22,891,934	6,510,672.0	11,798,448	1.83	41.48
18 B.B.#4	447	235,801	75.8	86.1	81.4	9,948	COAL	102,912	22,794,300	2,345,807.0	5,331,498	2.26	51.81
19 B.B. STA.	1,742	880,728	72.6	83.7	79.1	10,056	COAL	387,321	22,865,992	8,856,479.0	17,129,946	1.94	44.23
20 PHILLIPS #1 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
21 PHILLIPS #2 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
22 SEB-PHILLIPS TOTAL	34	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
23 POLK COAL	250	118,701	68.2	-	-	10,861	COAL	56,500	22,818,761	1,289,260.0	2,334,283	1.97	41.31
24 POLK OIL	250	13,189	7.6	-	-	8,401	LGT OIL	19,100	5,801,257	110,804.0	450,820	3.42	23.60
25 POLK TOTAL	250	131,890	75.8	88.5	92.1	10,615	-	-	-	1,400,064.0	2,785,103	2.11	-
26 GAN.C.T.#1	17	57	0.5	65.1	111.8	15,860	LGT OIL	156	5,794,872	904.0	3,720	6.53	23.85
27 B.B.C.T.#1	17	57	0.5	65.1	111.8	15,842	LGT OIL	156	5,788,462	903.0	3,580	6.28	22.95
28 B.B.C.T.#2	80	133	0.2	33.3	83.1	15,940	LGT OIL	365	5,808,219	2,120.0	8,376	6.30	22.95
29 B.B.C.T.#3	80	147	0.3	35.6	91.9	15,925	LGT OIL	404	5,794,554	2,341.0	9,271	6.31	22.95
30 C.T. TOTAL	194	394	0.3	39.8	93.4	15,909	LGT OIL	1,081	5,798,335	6,268.0	24,947	6.33	23.08
31 TOT COAL (GN,BB,POLK)	3,197	1,268,064	57.0	74.1	-	10,392	COAL	574,173	22,950,720	13,177,684.0	24,884,388	1.96	43.34
32 SYSTEM	3,629	1,283,585	50.8	72.1	75.1	10,382	-	-	-	13,325,642.0	25,441,708	1.98	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: MARCH 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	32	1,180	5.0	96.0	97.0	16,377	HVY OIL	3,057	6,321,557	19,325.0	50,773	4.30	16.61
2	H.P.#2	32	1,198	5.0	93.0	96.0	16,348	HVY OIL	3,098	6,321,821	19,585.0	51,454	4.29	16.61
3	H.P.#3	32	738	3.1	54.0	100.3	16,024	HVY OIL	1,871	6,320,684	11,826.0	31,075	4.21	16.61
4	H.P.#4	41	600	2.0	39.0	97.6	15,857	HVY OIL	1,505	6,321,595	9,514.0	24,996	4.17	16.61
5	H.P.#5	67	2,589	5.2	83.9	94.2	15,877	HVY OIL	6,503	6,321,083	41,106.0	108,006	4.17	16.61
6	H.P. STATION	204	6,305	4.2	73.5	96.1	16,075	HVY OIL	16,034	6,321,317	101,356.0	266,304	4.22	16.61
7	GAN.#1	114	29,748	35.1	80.1	57.6	11,982	COAL	14,583	24,442,502	356,445.0	597,698	2.01	40.99
8	GAN.#2	113	24,521	29.2	79.6	47.9	12,981	COAL	13,027	24,434,559	318,309.0	533,924	2.18	40.99
9	GAN.#3	155	27,973	24.3	55.5	63.3	11,919	COAL	16,797	19,850,152	333,423.0	688,441	2.46	40.99
10	GAN.#4	189	50,327	35.8	78.8	56.8	11,947	COAL	30,290	19,850,017	601,257.0	1,241,464	2.47	40.99
11	GAN.#5	242	32,265	17.9	29.4	56.5	10,514	COAL	13,839	24,527,639	339,438.0	567,204	1.76	40.99
12	GAN.#6	392	142,302	48.8	76.6	58.6	10,505	COAL	61,433	24,333,257	1,494,865.0	2,517,888	1.77	40.99
13	GANNON STA.	1,205	307,156	34.3	65.2	57.4	11,212	COAL	149,969	22,962,992	3,443,737.0	6,146,619	2.00	40.99
14	B.B.#1	426	244,689	77.2	82.9	84.3	10,074	COAL	108,143	22,792,904	2,464,893.0	4,484,346	1.83	41.47
15	B.B.#2	426	167,419	52.8	54.7	88.7	10,047	COAL	73,550	22,870,102	1,682,096.0	3,049,884	1.82	41.47
16	B.B.#3	443	228,681	69.4	80.9	76.6	10,170	COAL	100,984	23,030,361	2,325,700.0	4,187,485	1.83	41.47
17	B.B. 1 - 3	1,295	640,789	66.5	72.9	82.4	10,101	COAL	282,677	22,897,827	6,472,689.0	11,721,715	1.83	41.47
18	B.B.#4	447	266,288	80.1	86.0	86.1	9,962	COAL	116,382	22,794,186	2,652,833.0	6,019,201	2.26	51.72
19	B.B. STA.	1,742	907,077	70.0	76.3	83.5	10,060	COAL	399,059	22,867,601	9,125,522.0	17,740,918	1.96	44.46
20	PHILLIPS #1 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
21	PHILLIPS #2 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
22	SEB-PHILLIPS TOTAL	34	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
23	POLK COAL	250	128,997	69.4	-	-	10,859	COAL	61,400	22,813,453	1,400,746.0	2,517,686	1.95	41.00
24	POLK OIL	250	14,333	7.7	-	-	8,391	LGT OIL	20,700	5,810,145	120,270.0	486,486	3.39	23.50
25	POLK TOTAL	250	143,330	77.1	88.6	93.5	10,612	-	-	-	1,521,016.0	3,004,172	2.10	-
26	GAN.C.T.#1	17	126	1.0	64.9	92.6	16,063	LGT OIL	349	5,799,427	2,024.0	8,389	6.66	24.04
27	B.B.C.T.#1	17	128	1.0	64.9	94.1	15,977	LGT OIL	353	5,793,201	2,045.0	8,091	6.32	22.92
28	B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
29	B.B.C.T.#3	80	659	1.1	69.1	91.5	15,989	LGT OIL	1,817	5,799,119	10,537.0	41,646	6.32	22.92
30	C.T. TOTAL	194	913	0.6	39.9	92.0	15,998	LGT OIL	2,519	5,798,333	14,606.0	58,126	6.37	23.08
31	TOT COAL (GN,BB,POLK)	3,197	1,343,230	56.5	66.1	-	10,400	COAL	610,428	22,885,590	13,970,005.0	26,405,221	1.97	43.26
32	SYSTEM	3,629	1,364,781	50.5	64.5	83.7	10,409	-	-	-	14,206,237.0	27,216,137	1.99	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: APRIL 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	30	5,003	23.2	96.0	52.9	17,953	HVY OIL	14,210	6,320,830	89,819.0	238,241	4.76	16.77
2	H.P.#2	30	4,798	22.2	93.0	52.3	16,805	HVY OIL	12,756	6,321,104	80,632.0	213,863	4.46	16.77
3	H.P.#3	30	4,953	22.9	93.0	54.0	17,820	HVY OIL	13,963	6,321,134	88,262.0	234,100	4.73	16.77
4	H.P.#4	39	4,902	17.5	62.0	57.1	17,093	HVY OIL	13,256	6,320,987	83,791.0	222,246	4.53	16.77
5	H.P.#5	67	3,632	7.5	28.0	55.3	18,033	HVY OIL	10,362	6,320,884	65,497.0	173,726	4.78	16.77
6	H.P. STATION	196	23,288	16.5	65.1	54.2	17,520	HVY OIL	64,547	6,320,991	408,001.0	1,082,176	4.65	16.77
7	GAN.#1	114	23,825	29.0	80.1	90.5	11,424	COAL	10,887	25,000,551	272,181.0	443,425	1.86	40.73
8	GAN.#2	113	732	0.9	2.5	72.0	12,116	COAL	355	24,983,099	8,869.0	14,459	1.98	40.73
9	GAN.#3	145	43,158	41.3	86.0	91.0	11,555	COAL	25,124	19,849,825	498,707.0	1,023,294	2.37	40.73
10	GAN.#4	179	60,180	46.7	78.9	87.8	11,502	COAL	34,871	19,849,675	692,178.0	1,420,287	2.36	40.73
11	GAN.#5	232	109,917	65.8	77.2	75.9	10,419	COAL	47,189	24,268,092	1,145,187.0	1,921,996	1.75	40.73
12	GAN.#6	372	169,859	63.4	76.6	76.2	10,381	COAL	72,815	24,216,315	1,763,311.0	2,965,736	1.75	40.73
13	GANNON STA.	1,155	407,671	49.0	71.4	79.8	10,745	COAL	191,241	22,905,303	4,380,433.0	7,789,197	1.91	40.73
14	B.B.#1	416	84,080	28.1	27.7	91.9	10,116	COAL	37,318	22,793,129	850,594.0	1,555,616	1.85	41.69
15	B.B.#2	416	201,433	67.3	65.1	94.9	10,021	COAL	88,266	22,870,177	2,018,659.0	3,679,405	1.83	41.69
16	B.B.#3	433	189,798	60.9	61.9	87.8	10,169	COAL	83,803	23,030,381	1,930,015.0	3,493,363	1.84	41.69
17	B.B. 1 - 3	1,265	475,311	52.2	51.7	91.5	10,097	COAL	209,387	22,920,563	4,799,268.0	8,728,384	1.84	41.69
18	B.B.#4	442	275,403	86.5	86.0	93.0	9,906	COAL	119,686	22,794,161	2,728,142.0	6,225,873	2.26	52.02
19	B.B. STA.	1,707	750,714	61.1	60.6	92.0	10,027	COAL	329,073	22,874,590	7,527,410.0	14,954,257	1.99	45.44
20	PHILLIPS #1 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
21	PHILLIPS #2 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
22	SEB-PHILLIPS TOTAL	34	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
23	POLK COAL	250	127,267	70.7	-	-	10,833	COAL	60,500	22,788,760	1,378,720.0	2,493,199	1.96	41.21
24	POLK OIL	250	14,141	7.9	-	-	8,379	LGT OIL	20,400	5,808,529	118,494.0	486,027	3.44	23.82
25	POLK TOTAL	250	141,408	78.6	88.6	95.4	10,588	-	-	-	1,497,214.0	2,979,226	2.11	-
26	GAN.C.T.#1	12	458	5.3	65.0	136.3	16,142	LGT OIL	1,275	5,798,431	7,393.0	29,711	6.49	23.30
27	B.B.C.T.#1	12	460	5.3	65.0	136.9	16,157	LGT OIL	1,281	5,801,717	7,432.0	29,640	6.44	23.14
28	B.B.C.T.#2	62	0	0.0	0.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
29	B.B.C.T.#3	62	2,380	5.3	69.1	120.0	16,033	LGT OIL	6,579	5,799,970	38,158.0	152,226	6.40	23.14
30	C.T. TOTAL	148	3298	3.1	39.5	124.2	16,065	LGT OIL	9,135	5,800,000	52,983.0	211,577	6.42	23.16
31	TOT COAL (GN,BB,POLK)	3,112	1,285,652	57.4	59.7	-	10,334	COAL	580,814	22,875,762	13,286,563.0	25,236,653	1.96	43.45
32	SYSTEM	3,490	1,326,379	52.8	58.6	96.6	10,454	-	-	-	13,866,041.0	27,016,433	2.04	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST

TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD/MONTH OF: MAY 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	30	3,637	16.3	96.0	37.2	19,298	HVY OIL	11,104	6,320,875	70,187.0	187,892	5.17	16.92
2	H.P.#2	30	3,475	15.6	93.0	36.7	17,263	HVY OIL	9,491	6,320,725	59,990.0	160,598	4.62	16.92
3	H.P.#3	30	3,590	16.1	93.0	37.9	19,428	HVY OIL	11,034	6,321,008	69,746.0	186,707	5.20	16.92
4	H.P.#4	39	5,207	17.9	93.0	42.3	18,159	HVY OIL	14,959	6,320,877	94,554.0	253,123	4.86	16.92
5	H.P.#5	67	5,910	11.9	62.2	41.4	19,795	HVY OIL	18,508	6,321,050	116,990.0	313,176	5.30	16.92
6	H.P. STATION	196	21,819	15.0	82.9	39.4	18,858	HVY OIL	65,096	6,320,926	411,467.0	1,101,496	5.05	16.92
7	GAN.#1	114	23,617	27.8	80.1	89.3	12,465	COAL	11,775	25,000,425	294,380.0	478,602	2.03	40.65
8	GAN.#2	113	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
9	GAN.#3	145	34,317	31.8	86.0	88.3	11,570	COAL	20,002	19,850,365	397,047.0	812,993	2.37	40.65
10	GAN.#4	179	66,333	49.8	78.8	91.5	10,270	COAL	34,318	19,850,079	681,215.0	1,394,875	2.10	40.65
11	GAN.#5	232	113,300	65.6	79.8	73.3	10,496	COAL	48,588	24,475,961	1,189,238.0	1,974,887	1.74	40.65
12	GAN.#6	372	171,130	61.8	76.6	74.3	10,462	COAL	73,968	24,203,480	1,790,283.0	3,006,472	1.76	40.65
13	GANNON STA.	1,155	408,697	47.6	71.6	78.2	10,649	COAL	188,651	23,069,917	4,352,163.0	7,667,829	1.88	40.65
14	B.B.#1	416	245,400	79.3	80.1	89.5	10,141	COAL	109,186	22,792,886	2,488,664.0	4,527,280	1.84	41.46
15	B.B.#2	416	267,004	86.3	84.8	93.4	10,032	COAL	117,116	22,870,154	2,678,461.0	4,856,089	1.82	41.46
16	B.B.#3	433	241,539	75.0	80.9	82.8	10,143	COAL	106,379	23,030,363	2,449,947.0	4,410,891	1.83	41.46
17	B.B. 1 - 3	1,265	753,943	80.1	81.9	88.5	10,103	COAL	332,681	22,896,024	7,617,072.0	13,794,260	1.83	41.46
18	B.B.#4	442	282,013	85.8	86.0	92.2	9,926	COAL	122,808	22,794,297	2,799,322.0	6,375,398	2.26	51.91
19	B.B. STA.	1,707	1,035,956	81.6	83.0	89.5	10,055	COAL	455,489	22,868,596	10,416,394.0	20,169,658	1.95	44.28
20	PHILLIPS #1 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
21	PHILLIPS #2 (HVY OIL)	17	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
22	SEB-PHILLIPS TOTAL	34	0	0.0	0.0	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
23	POLK COAL	250	72,107	38.8	-	-	10,852	COAL	34,300	22,814,286	782,530.0	1,439,317	2.00	41.96
24	POLK OIL	250	8,012	4.3	-	-	8,380	LGT OIL	11,600	5,787,759	67,138.0	276,278	3.45	23.82
25	POLK TOTAL	250	80,119	43.1	48.7	95.4	10,605	-	-	-	849,668.0	1,715,595	2.14	-
26	GAN.C.T.#1	12	61	0.7	64.9	127.1	16,148	LGT OIL	170	5,794,118	985.0	4,147	6.80	24.39
27	B.B.C.T.#1	12	61	0.7	64.9	127.1	16,082	LGT OIL	169	5,804,734	981.0	3,913	6.41	23.15
28	B.B.C.T.#2	62	226	0.5	51.1	121.5	16,071	LGT OIL	626	5,801,917	3,632.0	14,496	6.41	23.16
29	B.B.C.T.#3	62	318	0.7	69.1	128.2	16,031	LGT OIL	879	5,799,772	5,098.0	20,354	6.40	23.16
30	C.T. TOTAL	148	666	0.6	60.9	125.7	16,060	LGT OIL	1,844	5,800,434	10,696.0	42,910	6.44	23.27
31	TOT COAL (GN,BB,POLK)	3,112	1,516,760	65.5	72.1	-	10,253	COAL	676,440	22,921,831	15,551,067.0	29,276,804	1.93	43.15
32	SYSTEM	3,490	1,547,257	59.6	71.5	89.1	10,367	-	-	-	16,040,388.0	30,697,488	1.98	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

ST

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: JUNE 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	30	4,644	21.5	96.0	49.0	18,132	HVY OIL	13,321	6,321,072	84,203.0	225,613	4.86	16.94
2	H.P.#2	30	4,346	20.1	93.1	47.3	16,940	HVY OIL	11,647	6,321,199	73,623.0	197,261	4.54	16.94
3	H.P.#3	30	4,579	21.2	93.1	49.9	18,182	HVY OIL	13,171	6,321,236	83,257.0	223,073	4.87	16.94
4	H.P.#4	39	6,270	22.3	93.1	52.5	17,618	HVY OIL	17,476	6,320,954	110,465.0	295,985	4.72	16.94
5	H.P.#5	67	10,220	21.2	83.9	53.9	18,479	HVY OIL	29,878	6,320,905	188,856.0	506,034	4.95	16.94
6	H.P. STATION	196	30,059	21.3	90.4	51.2	17,978	HVY OIL	85,493	6,321,032	540,404.0	1,447,966	4.82	16.94
7	GAN.#1	114	22,294	27.2	80.1	88.9	12,673	COAL	11,302	24,999,115	282,540.0	457,104	2.05	40.44
8	GAN.#2	113	25,836	31.8	79.4	87.6	12,630	COAL	13,053	24,999,157	326,314.0	527,923	2.04	40.44
9	GAN.#3	145	40,134	38.4	86.0	89.9	11,606	COAL	23,465	19,850,330	465,788.0	949,032	2.36	40.44
10	GAN.#4	179	55,879	43.4	78.9	87.9	11,582	COAL	32,603	19,849,983	647,169.0	1,318,614	2.36	40.44
11	GAN.#5	232	114,241	68.4	79.9	76.3	10,597	COAL	49,900	24,260,601	1,210,604.0	2,018,183	1.77	40.44
12	GAN.#6	372	171,710	64.1	76.6	77.1	10,518	COAL	74,573	24,219,490	1,806,120.0	3,016,072	1.76	40.44
13	GANNON STA.	1,155	430,094	51.7	79.4	80.4	11,017	COAL	204,896	23,126,537	4,738,535.0	8,286,928	1.93	40.44
14	B.B.#1	416	246,653	82.3	82.8	90.0	10,161	COAL	109,952	22,792,991	2,506,135.0	4,556,406	1.85	41.44
15	B.B.#2	416	260,372	86.9	84.7	94.0	10,063	COAL	114,565	22,870,275	2,620,133.0	4,747,569	1.82	41.44
16	B.B.#3	433	240,058	77.0	81.0	85.2	10,185	COAL	106,166	23,030,396	2,445,045.0	4,399,514	1.83	41.44
17	B.B. 1 - 3	1,265	747,083	82.0	82.8	89.7	10,135	COAL	330,683	22,895,985	7,571,313.0	13,703,489	1.83	41.44
18	B.B.#4	442	270,748	85.1	86.0	91.4	10,013	COAL	118,933	22,794,262	2,710,990.0	6,199,797	2.29	52.13
19	B.B. STA.	1,707	1,017,831	82.8	83.6	90.1	10,102	COAL	449,616	22,869,077	10,282,303.0	19,903,286	1.96	44.27
20	PHILLIPS #1 (HVY OIL)	17	2,846	23.3	84.0	96.2	9,336	HVY OIL	4,203	6,321,437	26,569.0	92,701	3.26	22.06
21	PHILLIPS #2 (HVY OIL)	17	2,810	23.0	84.0	96.1	9,336	HVY OIL	4,150	6,321,205	26,233.0	91,532	3.26	22.06
22	SEB-PHILLIPS TOTAL	34	5,656	23.1	84.0	96.2	9,336	HVY OIL	8,353	6,321,322	52,802.0	184,233	3.26	22.06
23	POLK COAL	250	128,441	71.4	-	-	10,826	COAL	61,000	22,796,066	1,390,560.0	2,509,994	1.95	41.15
24	POLK OIL	250	14,271	7.9	-	-	8,374	LGT OIL	20,600	5,801,505	119,511.0	483,591	3.39	23.48
25	POLK TOTAL	250	142,712	79.3	88.6	96.3	10,581	-	-	-	1,510,071.0	2,993,585	2.10	-
26	GAN.C.T.#1	12	193	2.2	65.0	134.0	16,155	LGT OIL	538	5,795,539	3,118.0	12,628	6.54	23.47
27	B.B.C.T.#1	12	197	2.3	65.0	136.8	16,168	LGT OIL	549	5,801,457	3,185.0	12,601	6.40	22.95
28	B.B.C.T.#2	62	1,064	2.4	68.9	114.4	16,209	LGT OIL	2,973	5,800,875	17,246.0	68,236	6.41	22.95
29	B.B.C.T.#3	62	1,221	2.7	68.9	115.8	16,147	LGT OIL	3,399	5,800,235	19,715.0	78,014	6.39	22.95
30	C.T. TOTAL	148	2675	2.5	68.3	117.7	16,173	LGT OIL	7,459	5,800,241	43,264.0	171,479	6.41	22.99
31	TOT COAL (GN,BB,POLK)	3,112	1,576,366	70.4	75.4	-	10,411	COAL	715,512	22,936,580	16,411,398.0	30,700,208	1.95	42.91
32	SYSTEM	3,490	1,629,027	64.8	76.0	94.1	10,538	-	-	-	17,167,379.0	32,987,477	2.02	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: JULY 2000

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1	H.P.#1	30	5,305	23.8	96.0	54.2	17,992	HVY OIL	15,101	6,320,773	95,450.0	255,232	4.81	16.90
2	H.P.#2	30	4,897	21.9	93.0	51.5	16,958	HVY OIL	13,138	6,320,749	83,042.0	222,054	4.53	16.90
3	H.P.#3	30	5,060	22.7	93.0	53.2	18,273	HVY OIL	14,628	6,320,891	92,462.0	247,238	4.89	16.90
4	H.P.#4	39	6,957	24.0	93.0	56.3	17,654	HVY OIL	19,430	6,321,050	122,818.0	328,399	4.72	16.90
5	H.P.#5	67	11,375	22.8	83.9	57.9	18,275	HVY OIL	32,886	6,321,079	207,875.0	555,828	4.89	16.90
6	H.P. STATION	196	33,594	23.0	90.3	55.3	17,909	HVY OIL	95,183	6,320,950	601,647.0	1,608,751	4.79	16.90
7	GAN.#1	114	30,639	36.1	80.1	91.1	11,590	COAL	14,205	24,999,507	355,118.0	575,732	1.88	40.53
8	GAN.#2	113	26,904	32.0	79.6	90.2	12,826	COAL	13,803	25,000,217	345,078.0	559,439	2.08	40.53
9	GAN.#3	145	43,549	40.4	86.0	91.0	11,643	COAL	25,544	19,849,710	507,041.0	1,035,305	2.38	40.53
10	GAN.#4	179	59,126	44.4	78.8	88.6	11,650	COAL	34,701	19,849,889	688,811.0	1,406,440	2.38	40.53
11	GAN.#5	232	119,704	69.4	79.8	77.5	10,714	COAL	52,744	24,316,643	1,282,557.0	2,137,727	1.79	40.53
12	GAN.#6	372	183,145	66.2	76.6	79.5	10,577	COAL	80,145	24,169,268	1,937,046.0	3,248,297	1.77	40.53
13	GANNON STA.	1,155	463,067	53.9	79.4	82.3	11,047	COAL	221,142	23,132,878	5,115,651.0	8,962,940	1.94	40.53
14	B.B.#1	416	255,824	82.7	82.9	90.3	10,244	COAL	114,973	22,792,934	2,620,572.0	4,775,152	1.87	41.53
15	B.B.#2	416	270,053	87.3	84.8	94.5	10,103	COAL	119,292	22,870,276	2,728,241.0	4,954,532	1.83	41.53
16	B.B.#3	433	250,813	77.9	80.9	85.9	10,300	COAL	112,170	23,030,302	2,583,309.0	4,658,736	1.86	41.53
17	B.B. 1 - 3	1,265	776,690	82.5	82.8	90.2	10,213	COAL	346,435	22,896,422	7,932,122.0	14,388,420	1.85	41.53
18	B.B.#4	442	281,803	85.7	86.0	92.1	10,079	COAL	124,601	22,794,175	2,840,177.0	6,511,011	2.31	52.25
19	B.B. STA.	1,707	1,058,493	83.3	83.7	90.7	10,177	COAL	471,036	22,869,375	10,772,299.0	20,899,431	1.97	44.37
20	PHILLIPS #1 (HVY OIL)	17	3,297	26.1	84.0	98.4	9,339	HVY OIL	4,871	6,321,084	30,790.0	106,040	3.22	21.77
21	PHILLIPS #2 (HVY OIL)	17	3,263	25.8	84.0	98.4	9,339	HVY OIL	4,821	6,320,888	30,473.0	104,952	3.22	21.77
22	SEB-PHILLIPS TOTAL	34	6,560	25.9	84.0	98.4	9,339	HVY OIL	9,692	6,320,986	61,263.0	210,992	3.22	21.77
23	POLK COAL	250	132,870	71.4	-	-	10,836	COAL	63,100	22,816,894	1,439,746.0	2,602,339	1.96	41.24
24	POLK OIL	250	14,763	7.9	-	-	8,374	LGT OIL	21,300	5,803,803	123,621.0	499,653	3.38	23.46
25	POLK TOTAL	250	147,633	79.4	88.6	96.3	10,590	-	-	-	1,563,367.0	3,101,992	2.10	-
26	GAN.C.T.#1	12	356	4.0	64.9	134.8	16,174	LGT OIL	993	5,798,590	5,758.0	22,979	6.45	23.14
27	B.B.C.T.#1	12	363	4.1	64.9	137.5	16,179	LGT OIL	1,013	5,797,631	5,873.0	23,227	6.40	22.93
28	B.B.C.T.#2	62	1,950	4.2	69.1	116.5	16,187	LGT OIL	5,442	5,800,074	31,564.0	124,780	6.40	22.93
29	B.B.C.T.#3	62	2,208	4.8	69.1	118.7	16,128	LGT OIL	6,139	5,800,619	35,610.0	140,761	6.38	22.93
30	C.T. TOTAL	148	4877	4.4	68.4	120.1	16,158	LGT OIL	13,587	5,800,029	78,805.0	311,747	6.39	22.94
31	TOT COAL (GN,BB,POLK)	3,112	1,654,430	71.5	75.4	-	10,474	COAL	755,278	22,942,143	17,327,696.0	32,464,710	1.96	42.98
32	SYSTEM	3,490	1,714,224	66.0	76.0	95.2	10,613	-	-	-	18,193,032.0	35,095,853	2.05	-

LEGEND: H.P. = HOOKERS POINT B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
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SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: AUGUST 2000

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1 H.P.#1	30	4,826	21.6	96.0	49.2	18,398	HVY OIL	14,047	6,320,923	88,790.0	235,132	4.87	16.74
2 H.P.#2	30	4,485	20.1	93.0	47.2	17,116	HVY OIL	12,144	6,321,146	76,764.0	203,277	4.53	16.74
3 H.P.#3	30	4,609	20.6	93.0	48.5	18,680	HVY OIL	13,620	6,321,145	86,094.0	227,984	4.95	16.74
4 H.P.#4	39	6,441	22.2	93.0	52.1	17,896	HVY OIL	18,236	6,321,068	115,271.0	305,251	4.74	16.74
5 H.P.#5	67	10,428	20.9	83.9	53.1	18,720	HVY OIL	30,884	6,320,911	195,215.0	516,965	4.96	16.74
6 H.P. STATION	196	30,789	21.1	90.3	50.6	18,258	HVY OIL	88,931	6,321,013	562,134.0	1,488,609	4.83	16.74
7 GAN.#1	114	30,530	36.0	80.1	91.4	11,588	COAL	14,152	24,999,505	353,793.0	575,571	1.89	40.67
8 GAN.#2	113	26,594	31.6	79.6	89.8	12,825	COAL	13,643	25,000,293	341,079.0	554,869	2.09	40.67
9 GAN.#3	145	43,627	40.4	86.0	90.6	11,646	COAL	25,596	19,850,289	508,088.0	1,041,005	2.39	40.67
10 GAN.#4	179	59,632	44.8	78.8	88.4	11,654	COAL	35,010	19,850,071	694,951.0	1,423,878	2.39	40.67
11 GAN.#5	232	121,038	70.1	79.8	78.3	10,703	COAL	53,279	24,314,965	1,295,477.0	2,166,890	1.79	40.67
12 GAN.#6	372	185,538	67.0	76.6	80.6	10,565	COAL	81,182	24,145,870	1,960,210.0	3,301,722	1.78	40.67
13 GANNON STA.	1,155	466,959	54.3	79.4	82.9	11,037	COAL	222,862	23,124,615	5,153,598.0	9,063,935	1.94	40.67
14 B.B.#1	416	256,491	82.9	82.9	90.5	10,244	COAL	115,279	22,792,989	2,627,553.0	4,781,716	1.86	41.48
15 B.B.#2	416	270,442	87.4	84.8	94.6	10,103	COAL	119,465	22,870,205	2,732,189.0	4,955,349	1.83	41.48
16 B.B.#3	433	253,471	78.7	80.9	86.9	10,296	COAL	113,315	23,030,481	2,609,699.0	4,700,250	1.85	41.48
17 B.B. 1 - 3	1,265	780,404	82.9	82.8	90.6	10,212	COAL	348,059	22,896,811	7,969,441.0	14,437,315	1.85	41.48
18 B.B.#4	442	282,650	86.0	86.0	92.4	10,079	COAL	124,976	22,794,248	2,848,734.0	6,535,308	2.31	52.29
19 B.B. STA.	1,707	1,063,054	83.7	83.7	91.1	10,177	COAL	473,035	22,869,714	10,818,175.0	20,972,623	1.97	44.34
20 PHILLIPS #1 (HVY OIL)	17	2,791	22.1	84.0	97.7	9,337	HVY OIL	4,123	6,320,398	26,059.0	90,026	3.23	21.84
21 PHILLIPS #2 (HVY OIL)	17	2,762	21.8	84.0	97.3	9,337	HVY OIL	4,080	6,320,588	25,788.0	89,089	3.23	21.84
22 SEB-PHILLIPS TOTAL	34	5,553	22.0	84.0	97.5	9,337	HVY OIL	8,203	6,320,493	51,847.0	179,117	3.23	21.84
23 POLK COAL	250	133,056	71.5	-	-	10,835	COAL	63,200	22,810,380	1,441,616.0	2,605,412	1.96	41.22
24 POLK OIL	250	14,784	7.9	-	-	8,373	LGT OIL	21,300	5,811,362	123,782.0	505,742	3.42	23.74
25 POLK TOTAL	250	147,840	79.5	88.6	96.5	10,588	-	-	-	1,565,398.0	3,111,154	2.10	-
26 GAN.C.T.#1	12	221	2.5	64.9	131.5	16,217	LGT OIL	618	5,799,353	3,584.0	14,497	6.56	23.46
27 B.B.C.T.#1	12	226	2.5	64.9	134.5	16,221	LGT OIL	632	5,800,633	3,666.0	14,611	6.47	23.12
28 B.B.C.T.#2	62	1,228	2.7	69.1	116.5	16,192	LGT OIL	3,428	5,800,467	19,884.0	79,251	6.45	23.12
29 B.B.C.T.#3	62	1,394	3.0	69.1	118.3	16,115	LGT OIL	3,873	5,800,155	22,464.0	89,539	6.42	23.12
30 C.T. TOTAL	148	3069	2.8	68.4	119.5	16,161	LGT OIL	8,551	5,800,257	49,598.0	197,898	6.45	23.14
31 TOT COAL (GN,BB,POLK)	3,112	1,663,069	71.8	75.4	-	10,471	COAL	759,097	22,939,610	17,413,389.0	32,641,970	1.96	43.00
32 SYSTEM	3,490	1,717,264	66.1	76.0	95.4	10,599	-	-	-	18,200,750.0	35,013,336	2.04	-

LEGEND: H.P. = HOOKERS POIN B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
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SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: SEPTEMBER 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	30	2,353	10.9	96.0	98.0	15,978	HVY OIL	5,948	6,320,780	37,596.0	100,141	4.26	16.84
2	H.P.#2	30	2,198	10.2	93.1	97.7	16,047	HVY OIL	5,580	6,320,968	35,271.0	93,946	4.27	16.84
3	H.P.#3	30	2,368	11.0	93.1	97.4	15,884	HVY OIL	5,951	6,320,618	37,614.0	100,192	4.23	16.84
4	H.P.#4	39	2,740	9.8	93.1	96.2	16,158	HVY OIL	7,004	6,320,959	44,272.0	117,920	4.30	16.84
5	H.P.#5	67	4,091	8.5	83.9	93.9	16,189	HVY OIL	10,478	6,320,958	66,231.0	176,409	4.31	16.84
6	H.P. STATION	196	13,750	9.7	90.4	96.3	16,072	HVY OIL	34,961	6,320,872	220,964.0	588,608	4.28	16.84
7	GAN.#1	114	21,858	26.6	58.9	93.5	11,497	COAL	10,052	25,000,298	251,303.0	409,653	1.87	40.75
8	GAN.#2	113	27,041	33.2	79.4	91.3	12,629	COAL	13,660	25,000,073	341,501.0	556,691	2.06	40.75
9	GAN.#3	145	39,827	38.1	86.0	90.6	11,594	COAL	23,262	19,849,884	461,748.0	948,005	2.38	40.75
10	GAN.#4	179	55,837	43.3	78.9	88.1	11,581	COAL	32,577	19,849,955	646,652.0	1,327,623	2.38	40.75
11	GAN.#5	232	115,341	69.0	79.9	77.1	10,594	COAL	50,078	24,399,457	1,221,876.0	2,040,848	1.77	40.75
12	GAN.#6	372	174,850	65.3	76.6	78.5	10,514	COAL	75,882	24,225,706	1,838,295.0	3,092,448	1.77	40.75
13	GANNON STA.	1,155	434,754	52.3	77.3	81.6	10,952	COAL	205,511	23,168,468	4,761,375.0	8,375,268	1.93	40.75
14	B.B.#1	416	247,225	82.5	82.8	90.2	10,161	COAL	110,212	22,792,890	2,512,050.0	4,573,528	1.85	41.50
15	B.B.#2	416	260,963	87.1	84.7	94.2	10,063	COAL	114,820	22,870,145	2,625,950.0	4,764,748	1.83	41.50
16	B.B.#3	433	242,205	77.7	81.0	85.9	10,182	COAL	107,079	23,030,426	2,466,075.0	4,443,516	1.83	41.50
17	B.B. 1 - 3	1,265	750,393	82.4	82.8	90.1	10,133	COAL	332,111	22,896,185	7,604,075.0	13,781,792	1.84	41.50
18	B.B.#4	442	271,475	85.3	86.0	91.7	10,013	COAL	119,247	22,794,309	2,716,153.0	6,255,938	2.30	52.46
19	B.B. STA.	1,707	1,021,868	83.1	83.6	90.5	10,101	COAL	451,358	22,869,270	10,322,228.0	20,037,730	1.96	44.39
20	PHILLIPS #1 (HVY OIL)	17	3,053	24.9	84.0	98.1	9,338	HVY OIL	4,511	6,320,106	28,510.0	98,002	3.21	21.73
21	PHILLIPS #2 (HVY OIL)	17	3,021	24.7	84.0	98.2	9,338	HVY OIL	4,463	6,321,084	28,211.0	96,959	3.21	21.73
22	SEB-PHILLIPS TOTAL	34	6,074	24.8	84.0	98.2	9,338	HVY OIL	8,974	6,320,593	56,721.0	194,961	3.21	21.73
23	POLK COAL	250	128,089	71.2	-	-	10,828	COAL	60,800	22,812,500	1,387,000.0	2,499,477	1.95	41.11
24	POLK OIL	250	14,232	7.9	-	-	8,376	LGT OIL	20,600	5,786,650	119,205.0	501,901	3.53	24.36
25	POLK TOTAL	250	142,321	79.1	88.6	96.0	10,583	-	-	-	1,506,205.0	3,001,378	2.11	-
26	GAN.C.T.#1	12	115	1.3	65.0	136.9	16,104	LGT OIL	319	5,805,643	1,852.0	7,783	6.77	24.40
27	B.B.C.T.#1	12	114	1.3	65.0	135.7	16,140	LGT OIL	317	5,804,416	1,840.0	7,446	6.53	23.49
28	B.B.C.T.#2	62	577	1.3	68.9	116.3	16,016	LGT OIL	1,593	5,801,004	9,241.0	37,417	6.48	23.49
29	B.B.C.T.#3	62	583	1.3	68.9	117.5	15,971	LGT OIL	1,605	5,801,246	9,311.0	37,699	6.47	23.49
30	C.T. TOTAL	148	1389	1.3	68.3	119.7	16,014	LGT OIL	3,834	5,801,774	22,244.0	90,345	6.50	23.56
31	TOT COAL (GN,BB,POLK)	3,112	1,584,711	70.7	74.6	-	10,393	COAL	717,669	22,950,139	16,470,603.0	30,912,475	1.95	43.07
32	SYSTEM	3,490	1,620,156	64.5	75.3	96.2	10,425	-	-	-	16,869,757.0	32,268,290	1.99	-

LEGEND: H.P. = HOOKERS POIN B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: OCTOBER 2000

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1	H.P.#1	32	0	0.0	0.1	0.0	0	HVY OIL	0	0	0.0	0	0.00	0.00
2	H.P.#2	32	1,117	4.7	93.0	97.0	16,456	HVY OIL	2,908	6,320,839	18,381.0	49,378	4.42	16.98
3	H.P.#3	32	1,164	4.9	93.0	98.3	16,200	HVY OIL	2,983	6,321,488	18,857.0	50,651	4.35	16.98
4	H.P.#4	41	1,557	5.1	93.0	97.4	16,128	HVY OIL	3,973	6,320,413	25,111.0	67,461	4.33	16.98
5	H.P.#5	67	2,486	5.0	83.9	95.1	16,112	HVY OIL	6,337	6,320,656	40,054.0	107,602	4.33	16.98
6	H.P. STATION	204	6,324	4.2	75.4	96.6	16,193	HVY OIL	16,201	6,320,783	102,403.0	275,092	4.35	16.98
7	GAN.#1	114	18,560	21.9	46.6	94.1	11,442	COAL	8,495	24,999,529	212,371.0	347,521	1.87	40.91
8	GAN.#2	113	27,339	32.5	79.6	90.6	12,421	COAL	13,583	25,000,883	339,587.0	555,666	2.03	40.91
9	GAN.#3	155	45,699	39.6	86.0	88.3	11,598	COAL	26,702	19,849,712	530,027.0	1,092,349	2.39	40.91
10	GAN.#4	189	26,242	18.7	33.0	90.7	11,538	COAL	15,253	19,850,456	302,779.0	623,983	2.38	40.91
11	GAN.#5	242	112,647	62.6	79.7	69.9	10,569	COAL	48,895	24,349,627	1,190,575.0	2,000,240	1.78	40.91
12	GAN.#6	392	170,071	58.3	76.6	70.1	10,530	COAL	73,928	24,224,313	1,790,855.0	3,024,313	1.78	40.91
13	GANNON STA.	1,205	400,558	44.7	69.0	75.0	10,900	COAL	186,856	23,366,625	4,366,194.0	7,644,072	1.91	40.91
14	B.B.#1	426	254,592	80.3	83.0	87.8	10,168	COAL	113,570	22,792,806	2,588,579.0	4,743,413	1.86	41.77
15	B.B.#2	426	265,565	83.8	84.8	90.7	10,051	COAL	116,715	22,870,154	2,669,290.0	4,874,769	1.84	41.77
16	B.B.#3	443	158,499	48.1	52.3	82.4	10,139	COAL	69,780	23,030,295	1,607,054.0	2,914,461	1.84	41.77
17	B.B. 1 - 3	1,295	678,656	70.4	73.1	87.6	10,115	COAL	300,065	22,878,120	6,864,923.0	12,532,643	1.85	41.77
18	B.B.#4	447	273,794	82.3	86.0	88.5	9,953	COAL	119,546	22,794,330	2,724,971.0	6,278,542	2.29	52.52
19	B.B. STA.	1,742	952,450	73.5	76.4	87.8	10,069	COAL	419,611	22,854,248	9,589,894.0	18,811,185	1.98	44.83
20	PHILLIPS #1 (HVY OIL)	17	3,069	24.3	84.0	93.5	9,332	HVY OIL	4,531	6,320,900	28,640.0	101,219	3.30	22.34
21	PHILLIPS #2 (HVY OIL)	17	3,034	24.0	84.0	93.4	9,332	HVY OIL	4,479	6,321,500	28,314.0	100,057	3.30	22.34
22	SEB-PHILLIPS TOTAL	34	6,103	24.1	84.0	93.5	9,332	HVY OIL	9,010	6,321,199	56,954.0	201,276	3.30	22.34
23	POLK COAL	250	130,992	70.4	-	-	10,847	COAL	62,300	22,806,196	1,420,826.0	2,571,909	1.96	41.28
24	POLK OIL	250	14,555	7.8	-	-	8,382	LGT OIL	21,000	5,809,333	121,996.0	524,105	3.60	24.96
25	FUTURE GAS C.T.	180	13,581	10.1	-	-	14,552	GAS	191,900	1,029,859	197,630.0	515,463	3.80	2.69
26	FUTURE OIL C.T.	180	13,514	10.1	-	-	8,618	LGT OIL	20,100	5,794,527	116,470.0	524,481	3.88	26.09
27	POLK TOTAL	430	172,642	54.0	88.6	48.1	10,756	-	-	-	1,856,922.0	4,135,958	2.40	-
28	GAN.C.T.#1	17	96	0.8	65.0	94.1	16,156	LGT OIL	267	5,808,989	1,551.0	6,512	6.78	24.39
29	B.B.C.T.#1	17	53	0.4	35.7	103.9	16,019	LGT OIL	146	5,815,068	849.0	3,485	6.58	23.87
30	B.B.C.T.#2	80	494	0.8	69.1	88.2	16,075	LGT OIL	1,369	5,800,584	7,941.0	32,673	6.61	23.87
31	B.B.C.T.#3	80	517	0.9	69.1	92.3	16,025	LGT OIL	1,428	5,801,821	8,285.0	34,081	6.59	23.87
32	C.T. TOTAL	194	1160	0.8	65.8	91.1	16,057	LGT OIL	3,210	5,802,492	18,626.0	76,751	6.62	23.91
33	TOT COAL (GN,BB,POLK)	3,197	1,484,000	62.4	67.7	-	10,362	COAL	668,767	22,992,932	15,376,914.0	29,027,166	1.96	43.40
34	SYSTEM	3,809	1,539,237	54.3	64.9	94.3	10,389	-	-	-	15,990,993.0	31,144,334	2.02	-

LEGEND: H.P. = HOOKERS POIN B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: NOVEMBER 2000

(A) PLANT/UNIT	(B) NET CAPABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1 H.P.#1	32	113	0.5	16.0	88.3	16,434	HVY OIL	294	6,316,327	1,857.0	4,994	4.42	16.99
2 H.P.#2	32	601	2.6	77.5	98.8	16,346	HVY OIL	1,554	6,321,750	9,824.0	26,395	4.39	16.99
3 H.P.#3	32	7,640	33.2	93.1	955.0	1,604	HVY OIL	1,938	6,321,465	12,251.0	32,918	0.43	16.99
4 H.P.#4	41	1,023	3.5	93.1	96.0	15,857	HVY OIL	2,566	6,321,902	16,222.0	43,585	4.26	16.99
5 H.P.#5	67	1,616	3.3	83.9	96.5	15,861	HVY OIL	4,055	6,320,838	25,631.0	68,876	4.26	16.99
6 H.P. STATION	204	10,993	7.5	75.5	257.0	5,984	HVY OIL	10,407	6,321,226	65,785.0	176,768	1.61	16.99
7 GAN.#1	114	23,565	28.7	80.1	89.1	11,403	COAL	10,749	24,999,628	268,721.0	443,399	1.88	41.25
8 GAN.#2	113	16,941	20.8	79.4	87.7	12,212	COAL	8,275	25,001,450	206,887.0	341,338	2.01	41.25
9 GAN.#3	155	36,616	32.8	86.0	83.8	11,540	COAL	21,287	19,849,486	422,536.0	878,075	2.40	41.25
10 GAN.#4	189	9,041	6.6	15.7	88.6	11,434	COAL	5,208	19,848,886	103,373.0	214,827	2.38	41.25
11 GAN.#5	242	102,367	58.8	79.9	65.6	10,417	COAL	43,832	24,328,961	1,066,387.0	1,808,041	1.77	41.25
12 GAN.#6	392	124,139	44.0	61.3	66.1	10,416	COAL	53,439	24,195,700	1,292,994.0	2,204,323	1.78	41.25
13 GANNON STA.	1,205	312,669	36.0	64.5	70.5	10,749	COAL	142,790	23,537,349	3,360,898.0	5,889,993	1.88	41.25
14 B.B.#1	426	240,482	78.4	82.8	85.7	10,080	COAL	106,354	22,792,974	2,424,124.0	4,432,082	1.84	41.67
15 B.B.#2	426	256,302	83.6	84.7	90.3	10,043	COAL	112,544	22,870,282	2,573,913.0	4,690,037	1.83	41.67
16 B.B.#3	443	206,306	64.7	72.8	79.5	10,158	COAL	90,997	23,030,485	2,095,705.0	3,792,111	1.84	41.67
17 B.B. 1 - 3	1,295	703,090	75.4	80.0	85.3	10,089	COAL	309,895	22,890,792	7,093,742.0	12,914,230	1.84	41.67
18 B.B.#4	447	203,590	63.3	66.0	88.6	9,947	COAL	88,844	22,794,291	2,025,136.0	4,623,602	2.27	52.04
19 B.B. STA.	1,742	906,680	72.3	76.4	86.0	10,057	COAL	398,739	22,869,290	9,118,878.0	17,537,832	1.93	43.98
20 PHILLIPS #1 (HVY OIL)	17	1,051	8.6	84.0	98.1	9,338	HVY OIL	1,552	6,323,454	9,814.0	36,387	3.46	23.45
21 PHILLIPS #2 (HVY OIL)	17	1,042	8.5	84.0	98.9	9,338	HVY OIL	1,539	6,322,287	9,730.0	36,082	3.46	23.45
22 SEB-PHILLIPS TOTAL	34	2,093	8.5	84.0	98.5	9,338	HVY OIL	3,091	6,322,873	19,544.0	72,469	3.46	23.45
23 POLK COAL	250	92,988	51.7	-	-	10,872	COAL	44,200	22,873,122	1,010,992.0	1,850,037	1.99	41.86
24 POLK OIL	250	10,332	5.7	-	-	8,387	LGT OIL	14,900	5,815,839	86,656.0	373,420	3.61	25.06
25 FUTURE GAS C.T.	180	4,948	3.8	-	-	14,898	GAS	71,600	1,029,525	73,714.0	202,470	4.09	2.83
26 FUTURE OIL C.T.	180	11,892	9.2	-	-	10,167	LGT OIL	20,800	5,812,885	120,908.0	527,143	4.43	25.34
27 POLK TOTAL	430	120,160	38.8	67.9	47.1	10,755	-	-	-	1,292,270.0	2,953,070	2.46	-
28 GAN.C.T.#1	17	24	0.2	36.8	141.2	16,333	LGT OIL	68	5,764,706	392.0	1,772	7.38	26.06
29 B.B.C.T.#1	17	41	0.3	65.0	80.4	16,220	LGT OIL	115	5,782,609	665.0	2,760	6.73	24.00
30 B.B.C.T.#2	80	205	0.4	68.9	85.4	16,054	LGT OIL	567	5,804,233	3,291.0	13,609	6.64	24.00
31 B.B.C.T.#3	80	207	0.4	68.9	86.3	15,947	LGT OIL	569	5,801,406	3,301.0	13,657	6.60	24.00
32 C.T. TOTAL	194	477	0.3	65.7	87.0	16,036	LGT OIL	1,319	5,799,090	7,649.0	31,798	6.67	24.11
33 TOT COAL (GN,BB,POLK)	3,197	1,312,337	57.0	66.0	-	10,260	COAL	585,729	23,032,440	13,490,768.0	25,277,862	1.93	43.16
34 SYSTEM	3,809	1,353,072	49.3	63.5	89.9	10,247	-	-	-	13,865,024.0	26,661,930	1.97	-

LEGEND: H.P. = HOOKERS POIN B.B. = BIG BEND HVY=HEAVY NAT=NATURAL
SEB=SEBRING GAN. = GANNON C.T. = COMBUSTION TURBINE LGT=LIGHT

SCHEDULE E4

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD/MONTH OF: DECEMBER 2000

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNE (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1 H.P.#1	32	217	0.9	96.0	96.9	16,253	HVY OIL	558	6,320,789	3,527.0	9,473	4.37	16.98
2 H.P.#2	32	57	0.2	24.1	89.1	16,263	HVY OIL	147	6,306,122	927.0	2,496	4.38	16.98
3 H.P.#3	32	219	0.9	93.0	97.8	15,941	HVY OIL	552	6,324,275	3,491.0	9,371	4.28	16.98
4 H.P.#4	41	319	1.0	93.0	97.3	15,715	HVY OIL	793	6,321,564	5,013.0	13,462	4.22	16.98
5 H.P.#5	67	448	0.9	83.9	95.5	15,806	HVY OIL	1,120	6,322,321	7,081.0	19,013	4.24	16.98
6 H.P. STATION	204	1,260	0.8	79.7	96.3	15,904	HVY OIL	3,170	6,321,451	20,039.0	53,815	4.27	16.98
7 GAN.#1	114	26,108	30.8	80.1	51.1	12,148	COAL	12,933	24,523,776	317,166.0	526,529	2.02	40.71
8 GAN.#2	113	24,554	29.2	79.6	47.8	12,940	COAL	12,710	24,999,056	317,738.0	517,451	2.11	40.71
9 GAN.#3	155	40,273	34.9	86.0	57.9	12,021	COAL	24,389	19,849,891	484,119.0	992,927	2.47	40.71
10 GAN.#4	189	44,963	32.0	78.8	50.8	12,046	COAL	27,286	19,850,143	541,631.0	1,110,870	2.47	40.71
11 GAN.#5	242	88,508	49.2	79.8	54.9	10,461	COAL	37,670	24,579,586	925,913.0	1,533,624	1.73	40.71
12 GAN.#6	392	72,168	24.7	39.5	57.7	10,462	COAL	30,758	24,546,264	754,994.0	1,252,222	1.74	40.71
13 GANNON STA.	1,205	296,574	33.1	67.3	54.2	11,267	COAL	145,746	22,927,291	3,341,561.0	5,933,623	2.00	40.71
14 B.B.#1	426	245,191	77.4	82.9	84.5	10,040	COAL	107,998	22,793,015	2,461,600.0	4,500,992	1.84	41.68
15 B.B.#2	426	256,863	81.0	84.8	87.8	10,059	COAL	112,979	22,870,321	2,583,866.0	4,708,583	1.83	41.68
16 B.B.#3	443	227,936	69.2	80.9	76.3	10,174	COAL	100,694	23,030,320	2,319,015.0	4,196,586	1.84	41.68
17 B.B. 1 - 3	1,295	729,990	75.8	82.8	82.8	10,088	COAL	321,671	22,894,451	7,364,481.0	13,406,161	1.84	41.68
18 B.B.#4	447	264,509	79.5	86.0	85.5	9,931	COAL	115,240	22,794,325	2,626,818.0	5,959,047	2.25	51.71
19 B.B. STA.	1,742	994,499	76.7	83.7	83.5	10,047	COAL	436,911	22,868,042	9,991,299.0	19,365,208	1.95	44.32
20 PHILLIPS #1 (HVY OIL)	17	353	2.8	84.0	98.9	9,340	HVY OIL	521	6,328,215	3,297.0	12,625	3.58	24.23
21 PHILLIPS #2 (HVY OIL)	17	347	2.7	84.0	97.2	9,340	HVY OIL	513	6,317,739	3,241.0	12,431	3.58	24.23
22 SEB-PHILLIPS TOTAL	34	700	2.8	84.0	98.0	9,340	HVY OIL	1,034	6,323,017	6,538.0	25,056	3.58	24.23
23 POLK COAL	250	128,059	68.8	-	-	10,874	COAL	61,000	22,828,230	1,392,522.0	2,583,748	2.02	42.36
24 POLK OIL	250	14,229	7.7	-	-	8,395	LGT OIL	20,600	5,798,398	119,447.0	511,945	3.60	24.85
25 FUTURE GAS C.T.	180	2,063	1.5	-	-	14,963	GAS	30,000	1,028,967	30,869.0	89,343	4.33	2.98
26 FUTURE OIL C.T.	180	4,127	3.1	-	-	9,210	LGT OIL	6,600	5,759,091	38,010.0	161,315	3.91	24.44
27 POLK TOTAL	430	148,478	46.4	88.6	52.4	10,647	-	-	-	1,580,848.0	3,346,351	2.25	-
28 GAN.C.T.#1	17	58	0.5	62.9	113.7	15,862	LGT OIL	159	5,786,164	920.0	3,953	6.82	24.86
29 B.B.C.T.#1	17	60	0.5	64.9	88.2	16,017	LGT OIL	166	5,789,157	961.0	3,981	6.64	23.98
30 B.B.C.T.#2	80	300	0.5	69.1	93.8	15,947	LGT OIL	825	5,798,788	4,784.0	19,784	6.59	23.98
31 B.B.C.T.#3	80	301	0.5	69.1	94.1	15,880	LGT OIL	824	5,800,971	4,780.0	19,760	6.56	23.98
32 C.T. TOTAL	194	719	0.5	68.2	94.7	15,918	LGT OIL	1,974	5,797,872	11,445.0	47,478	6.60	24.05
33 TOT COAL (GN,BB,POLK)	3,197	1,419,132	59.7	71.0	-	10,376	COAL	643,657	22,877,685	14,725,382.0	27,882,579	1.96	43.32
34 SYSTEM	3,809	1,442,230	50.9	68.1	82.9	10,367	-	-	-	14,951,730.0	28,771,531	1.99	-

LEGEND:
SEB=SEBRING
H.P. = HOOKERS POI
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
HVY=HEAVY
LGT=LIGHT
NAT=NATURAL

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU JUNE 2000

	HEAVY OIL	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00
1	PURCHASES:						
2	UNITS (BBL)	5,084	4,886	16,034	64,547	65,096	93,846
3	UNIT COST ($/BBL)	15.96	15.18	15.43	17.19	17.16	17.10
4	AMOUNT ($)	81,141	74,169	247,405	1,109,563	1,117,047	1,604,973
5	BURNED:						
6	UNITS (BBL)	5,084	4,886	16,034	64,547	65,096	93,846
7	UNIT COST ($/BBL)	16.74	16.69	16.61	16.77	16.92	17.39
8	AMOUNT ($)	85,094	81,553	266,304	1,082,176	1,101,496	1,632,199
9	ENDING INVENTORY:						
10	UNITS (BBL)	175,493	175,493	175,493	175,493	175,493	175,493
11	UNIT COST ($/BBL)	16.90	16.86	16.76	16.93	17.05	17.06
12	AMOUNT ($)	2,965,844	2,958,713	2,941,074	2,971,492	2,991,954	2,994,139
13	DAYS SUPPLY:	185	111	69	58	50	61
	LIGHT OIL						
14	PURCHASES:						
15	UNITS (BBL)	34,566	30,508	33,512	40,102	26,374	42,260
16	UNIT COST ($/BBL)	23.45	23.08	23.10	24.19	23.48	22.53
17	AMOUNT ($)	810,665	704,199	774,137	970,098	619,314	952,211
18	BURNED:						
19	UNITS (BBL)	22,397	20,181	23,219	29,535	13,444	28,059
20	UNIT COST ($/BBL)	23.69	23.57	23.46	23.62	23.74	23.35
21	AMOUNT ($)	530,656	475,767	544,612	697,604	319,188	655,070
22	ENDING INVENTORY:						
23	UNITS (BBL)	110,358	110,358	110,358	110,358	110,358	110,358
24	UNIT COST ($/BBL)	23.26	23.19	23.13	23.39	23.40	23.14
25	AMOUNT ($)	2,567,134	2,558,726	2,552,724	2,580,926	2,581,856	2,553,770
26	DAYS SUPPLY: NORMAL	95	102	91	79	68	72
27	DAYS SUPPLY: EMERGENCY	16	16	16	16	16	16
	COAL						
28	PURCHASES:						
29	UNITS (TONS)	693,400	600,400	639,400	622,200	648,200	661,200
30	UNIT COST ($/TON)	42.64	42.50	42.63	43.01	42.41	42.28
31	AMOUNT ($)	29,563,801	25,514,373	27,255,790	26,761,030	27,492,925	27,956,161
32	BURNED:						
33	UNITS (TONS)	630,429	574,173	610,428	580,814	678,440	715,512
34	UNIT COST ($/TON)	43.61	43.34	43.26	43.45	43.15	42.91
35	AMOUNT ($)	27,491,590	24,884,388	26,405,221	25,236,653	29,276,804	30,700,208
36	ENDING INVENTORY:						
37	UNITS (TONS)	926,471	952,698	981,670	1,023,056	992,816	938,504
38	UNIT COST ($/TON)	43.41	43.24	43.17	43.31	43.26	43.28
39	AMOUNT ($)	40,214,438	41,195,775	42,383,024	44,309,004	42,948,286	40,621,281
40	DAYS SUPPLY:	47	47	45	44	40	38
	NATURAL GAS						
41	PURCHASES:						
42	UNITS (MCF)	0	0	0	0	0	0
43	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT ($)	0	0	0	0	0	0
45	BURNED:						
46	UNITS (MCF)	0	0	0	0	0	0
47	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
48	AMOUNT ($)	0	0	0	0	0	0
49	ENDING INVENTORY:						
50	UNITS (MCF)	0	0	0	0	0	0
51	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52	AMOUNT ($)	0	0	0	0	0	0
53	DAYS SUPPLY:	0	0	0	0	0	0
	NUCLEAR						
54	BURNED:						
55	UNITS (MMBTU)	0	0	0	0	0	0
56	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57	AMOUNT ($)	0	0	0	0	0	0
	OTHER						
58	PURCHASES:						
59	UNITS (MMBTU)	0	0	0	0	0	0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61	AMOUNT ($)	0	0	0	0	0	0
62	BURNED:						
63	UNITS (MMBTU)	0	0	0	0	0	0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65	AMOUNT ($)	0	0	0	0	0	0
66	ENDING INVENTORY:						
67	UNITS (MMBTU)	0	0	0	0	0	0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69	AMOUNT ($)	0	0	0	0	0	0
70	DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING:
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED.
(2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JULY 2000 THRU DECEMBER 2000

	HEAVY OIL	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	TOTAL
1	PURCHASES:							
2	UNITS (BBL)	104,875	97,134	43,935	25,211	13,498	4,204	538,350
3	UNIT COST ($/BBL)	16.98	16.55	17.49	18.68	18.00	17.69	17.05
4	AMOUNT ($)	1,780,843	1,607,582	768,573	470,816	242,928	74,386	9,179,426
5	BURNED:							
6	UNITS (BBL)	104,875	97,134	43,935	25,211	13,498	4,204	538,350
7	UNIT COST ($/BBL)	17.35	17.17	17.83	18.90	18.46	18.76	17.32
8	AMOUNT ($)	1,819,743	1,667,726	783,569	476,368	249,237	78,871	9,324,336
9	ENDING INVENTORY:							
10	UNITS (BBL)	175,493	175,493	175,493	175,493	175,493	175,493	175,493
11	UNIT COST ($/BBL)	17.02	16.85	16.93	17.06	17.10	17.11	17.11
12	AMOUNT ($)	2,987,245	2,957,331	2,970,363	2,993,996	3,001,215	3,002,006	3,002,006
13	DAYS SUPPLY:	92	193	377	694	954	545	-
	LIGHT OIL							
14	PURCHASES:							
15	UNITS (BBL)	49,258	44,074	38,431	38,005	27,808	33,526	438,424
16	UNIT COST ($/BBL)	23.11	23.99	25.31	25.83	25.07	24.22	23.93
17	AMOUNT ($)	1,138,352	1,057,440	972,626	981,593	697,219	811,913	10,489,767
18	BURNED:							
19	UNITS (BBL)	34,887	29,851	24,434	24,210	16,219	22,574	289,010
20	UNIT COST ($/BBL)	23.26	23.57	24.24	46.48	57.49	31.93	28.06
21	AMOUNT ($)	811,400	703,640	592,246	1,125,337	932,361	720,738	8,108,619
22	ENDING INVENTORY:							
23	UNITS (BBL)	110,358	110,358	110,358	110,358	110,358	110,358	110,358
24	UNIT COST ($/BBL)	23.60	23.72	23.78	24.27	24.39	24.30	24.30
25	AMOUNT ($)	2,604,297	2,617,783	2,624,731	2,678,250	2,691,821	2,681,709	2,681,709
26	DAYS SUPPLY: NORMAL	72	69	69	77	78	74	-
27	DAYS SUPPLY: EMERGENCY	16	16	16	16	16	16	-
	COAL							
28	PURCHASES:							
29	UNITS (TONS)	687,200	648,200	778,200	700,600	643,600	668,600	7,991,200
30	UNIT COST ($/TON)	42.46	42.34	42.66	43.05	42.72	42.42	42.60
31	AMOUNT ($)	29,176,438	27,445,220	33,201,470	30,161,854	27,495,758	28,363,135	340,387,955
32	BURNED:							
33	UNITS (TONS)	755,278	759,097	717,669	668,767	585,729	643,657	7,919,993
34	UNIT COST ($/TON)	42.98	43.00	43.07	43.40	43.16	43.32	43.21
35	AMOUNT ($)	32,464,710	32,641,970	30,912,475	29,027,166	25,277,862	27,882,579	342,201,626
36	ENDING INVENTORY:							
37	UNITS (TONS)	870,426	759,529	820,060	851,893	909,764	934,707	934,707
38	UNIT COST ($/TON)	43.43	43.49	43.62	43.88	43.97	43.73	43.73
39	AMOUNT ($)	37,804,010	33,034,538	35,772,822	37,382,712	40,000,080	40,873,154	40,873,154
40	DAYS SUPPLY:	37	35	40	42	44	47	-
	NATURAL GAS							
41	PURCHASES:							
42	UNITS (MCF)	0	0	0	191,900	71,600	30,000	293,500
43	UNIT COST ($/MCF)	0.00	0.00	0.00	2.69	2.83	2.98	2.75
44	AMOUNT ($)	0	0	0	515,463	202,470	89,343	807,276
45	BURNED:							
46	UNITS (MCF)	0	0	0	191,900	71,600	30,000	293,500
47	UNIT COST ($/MCF)	0.00	0.00	0.00	2.69	2.83	2.98	2.75
48	AMOUNT ($)	0	0	0	515,463	202,470	89,343	807,276
49	ENDING INVENTORY:							
50	UNITS (MCF)	0	0	0	0	0	0	0
51	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	AMOUNT ($)	0	0	0	0	0	0	0
53	DAYS SUPPLY:	0	0	0	0	0	0	-
	NUCLEAR							
54	BURNED:							
55	UNITS (MMBTU)	0	0	0	0	0	0	0
56	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58	PURCHASES:							
59	UNITS (MMBTU)	0	0	0	0	0	0	0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	AMOUNT ($)	0	0	0	0	0	0	0
62	BURNED:							
63	UNITS (MMBTU)	0	0	0	0	0	0	0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	AMOUNT ($)	0	0	0	0	0	0	0
66	ENDING INVENTORY:							
67	UNITS (MMBTU)	0	0	0	0	0	0	0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69	AMOUNT ($)	0	0	0	0	0	0	0
70	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING:
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED.
(2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU JUNE 2000

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) cents/KWH (A) FUEL COST	(7) cents/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST $ (6)X(7B)	(10) 80% GAIN ON ECONOMY ENERGY SALES
Jan-00	VARIOUS		ECON.	190.0	0.0	190.0	3.158	3.842	6,000.00	7,300.00	1,040.00
	VARIOUS	JURISD.	SCH. -D	5,724.0	0.0	5,724.0	1.827	1.827	104,600.00	104,600.00	
	VARIOUS	SEPARATED	SCH. -D	9,896.0	0.0	9,896.0	1.725	1.899	170,700.00	187,900.00	
	HPP	SEPARATED	CONTRACT	9,961.0	0.0	9,961.0	2.306	3.194	229,700.00	318,200.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(18,100.00)		
	LESS VARIABLE O & M COSTS								(400.00)		
	PLUS 80% OF ECON. PROFITS								1,040.00		
TOTAL			-	137,371.0	0.0	137,371.0	2.438	2.529	3,349,633.00	3,474,093.00	
Feb-00	VARIOUS		ECON.	754.0	0.0	754.0	2.944	3.806	22,200.00	28,700.00	5,200.00
	VARIOUS	JURISD.	SCH. -D	5,644.0	0.0	5,644.0	1.820	1.820	102,700.00	102,700.00	
	VARIOUS	SEPARATED	SCH. -D	9,257.0	0.0	9,257.0	1.737	1.912	160,800.00	177,000.00	
	HPP	SEPARATED	CONTRACT	5,735.0	0.0	5,735.0	2.295	3.184	131,600.00	182,600.00	
	FMPA		SCH. -D	104,400.0	0.0	104,400.0	2.600	2.600	2,714,853.00	2,714,853.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(18,100.00)		
	LESS VARIABLE O & M COSTS								(1,600.00)		
	PLUS 80% OF ECON. PROFITS								5,200.00		
TOTAL			-	125,790.0	0.0	125,790.0	2.478	2.549	3,117,653.00	3,205,853.00	
Mar-00	VARIOUS		ECON.	12,790.0	0.0	12,790.0	2.242	2.892	286,800.00	369,900.00	66,480.00
	VARIOUS	JURISD.	SCH. -D	5,773.0	0.0	5,773.0	1.864	1.864	107,600.00	107,600.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	10,087.0	0.0	10,087.0	2.294	3.183	231,400.00	321,100.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(26,900.00)		
	PLUS 80% OF ECON. PROFITS								66,480.00		
TOTAL			-	140,250.0	0.0	140,250.0	2.511	2.606	3,521,473.00	3,654,693.00	
Apr-00	VARIOUS		ECON.	10,016.0	0.0	10,016.0	2.283	3.077	228,700.00	308,200.00	63,600.00
	VARIOUS	JURISD.	SCH. -D	5,675.0	0.0	5,675.0	2.033	2.033	115,400.00	115,400.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	19,801.0	0.0	19,801.0	2.295	3.183	454,400.00	630,300.00	
	FMPA		SCH. -D	108,000.0	0.0	108,000.0	2.579	2.579	2,785,473.00	2,785,473.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(21,000.00)		
	PLUS 80% OF ECON. PROFITS								63,600.00		
TOTAL			-	143,492.0	0.0	143,492.0	2.527	2.676	3,626,573.00	3,839,373.00	
May-00	VARIOUS		ECON.	7,495.0	0.0	7,495.0	2.108	2.694	158,000.00	201,900.00	35,120.00
	VARIOUS	JURISD.	SCH. -D	5,966.0	0.0	5,966.0	2.026	2.026	120,900.00	120,900.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	27,800.0	0.0	27,800.0	2.295	3.183	638,000.00	885,000.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(15,700.00)		
	PLUS 80% OF ECON. PROFITS								35,120.00		
TOTAL			-	152,861.0	0.0	152,861.0	2.481	2.659	3,792,413.00	4,063,893.00	
Jun-00	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,999.0	0.0	5,999.0	2.112	2.112	126,700.00	126,700.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	38,216.0	0.0	38,216.0	2.324	3.213	888,300.00	1,227,900.00	
	FMPA		SCH. -D	108,000.0	0.0	108,000.0	2.580	2.580	2,786,473.00	2,786,473.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								0.00		
	PLUS 80% OF ECON. PROFITS								0.00		
TOTAL			-	152,215.0	0.0	152,215.0	2.497	2.721	3,801,473.00	4,141,073.00	

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JULY 2000 THRU DECEMBER 2000

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) cents/KWH (A) FUEL COST	(7) cents/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST $ (6)X(7B)	(10) 80% GAIN ON ECONOMY ENERGY SALES
Jul-00	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,750.0	0.0	5,750.0	2.118	2.118	121,800.00	121,800.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	49,915.0	0.0	49,915.0	2.345	3.234	1,170,700.00	1,614,200.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								0.00		
	PLUS 80% OF ECON. PROFITS								0.00		
TOTAL			-	167,265.0	0.0	167,265.0	2.480	2.745	4,148,593.00	4,592,093.00	
Aug-00	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,864.0	0.0	5,864.0	2.140	2.140	125,500.00	125,500.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	39,909.0	0.0	39,909.0	2.347	3.236	936,700.00	1,291,300.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								0.00		
	PLUS 80% OF ECON. PROFITS								0.00		
TOTAL			-	157,373.0	0.0	157,373.0	2.490	2.715	3,918,293.00	4,272,893.00	
Sep-00	VARIOUS		ECON.	20,655.0	0.0	20,655.0	2.683	3.555	554,200.00	734,300.00	144,080.00
	VARIOUS	JURISD.	SCH. -D	5,824.0	0.0	5,824.0	2.100	2.100	122,300.00	122,300.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	21,567.0	0.0	21,567.0	2.339	3.228	504,500.00	696,100.00	
	FMPA		SCH. -D	108,000.0	0.0	108,000.0	2.579	2.579	2,785,473.00	2,785,473.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(43,400.00)		
	PLUS 80% OF ECON. PROFITS								144,080.00		
TOTAL			-	156,046.0	0.0	156,046.0	2.606	2.780	4,067,153.00	4,338,173.00	
Oct-00	VARIOUS		ECON.	5,459.0	0.0	5,459.0	2.370	3.019	129,400.00	164,800.00	28,320.00
	VARIOUS	JURISD.	SCH. -D	5,854.0	0.0	5,854.0	1.988	1.988	116,400.00	116,400.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	19,456.0	0.0	19,456.0	2.328	3.216	452,900.00	625,800.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(11,500.00)		
	PLUS 80% OF ECON. PROFITS								28,320.00		
TOTAL			-	142,369.0	0.0	142,369.0	2.509	2.643	3,571,613.00	3,763,093.00	
Nov-00	VARIOUS		ECON.	2,255.0	0.0	2,255.0	2.670	3.605	60,200.00	81,300.00	16,880.00
	VARIOUS	JURISD.	SCH. -D	5,784.0	0.0	5,784.0	1.952	1.952	112,900.00	112,900.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	10,609.0	0.0	10,609.0	2.306	3.194	244,600.00	338,800.00	
	FMPA		SCH. -D	108,000.0	0.0	108,000.0	2.579	2.579	2,785,473.00	2,785,473.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(4,700.00)		
	PLUS 80% OF ECON. PROFITS								16,880.00		
TOTAL			-	126,648.0	0.0	126,648.0	2.539	2.620	3,215,353.00	3,318,473.00	
Dec-00	VARIOUS		ECON.	2,538.0	0.0	2,538.0	3.085	3.794	78,300.00	96,300.00	14,400.00
	VARIOUS	JURISD.	SCH. -D	5,758.0	0.0	5,758.0	1.891	1.891	108,900.00	108,900.00	
	VARIOUS	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	12,690.0	0.0	12,690.0	2.287	3.176	290,200.00	403,000.00	
	FMPA		SCH. -D	111,600.0	0.0	111,600.0	2.559	2.559	2,856,093.00	2,856,093.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								0.00		
	LESS VARIABLE O & M COSTS								(5,300.00)		
	PLUS 80% OF ECON. PROFITS								14,400.00		
TOTAL			-	132,586.0	0.0	132,586.0	2.521	2.613	3,342,593.00	3,464,293.00	
Jan-00 THRU Dec-00	VARIOUS		ECON.	62,152.0	0.0	62,152.0	2.452	3.206	1,523,800.00	1,992,700.00	375,120.00
	VARIOUS	JURISD.	SCH. -D	69,615.0	0.0	69,615.0	1.991	1.991	1,385,700.00	1,385,700.00	
	VARIOUS	SEPARATED	SCH. -D	19,153.0	0.0	19,153.0	1.731	1.905	331,500.00	364,900.00	
	HPP	SEPARATED	CONTRACT	265,746.0	0.0	265,746.0	2.323	3.211	6,173,000.00	8,534,300.00	
	FMPA		SCH. -D	1,317,600.0	0.0	1,317,600.0	2.569	2.569	33,850,396.00	33,850,396.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(36,200.00)		
	LESS VARIABLE O & M COSTS								(130,500.00)		
	PLUS 80% OF ECON. PROFITS								375,120.00		
TOTAL			-	1,734,266.0	0.0	1,734,266.0	2.507	2.660	43,472,816.00	46,127,996.00	

SCHEDULE E7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU DECEMBER 2000

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUP-TIBLE	(7) MWH FOR FIRM	(8) cents/KWH (A) FUEL COST	(8) cents/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
Jan-00	VARIOUS	EMER.	4,440.0	0.0	2,161.0	2,279.0	7.372	7.372	168,000.00
	HPP	IPP	13,805.0	0.0	0.0	13,805.0	4.369	4.369	603,200.00
	VARIOUS	OTHER	23,880.0	0.0	0.0	23,880.0	3.039	3.039	725,700.00
TOTAL		-	42,125.0	0.0	2,161.0	39,964.0	3.746	3.746	1,496,900.00
Feb-00	VARIOUS	EMER.	3,472.0	0.0	1,925.0	1,547.0	7.369	7.369	114,000.00
	HPP	IPP	12,189.0	0.0	0.0	12,189.0	4.323	4.323	526,900.00
	VARIOUS	OTHER	22,560.0	0.0	0.0	22,560.0	3.024	3.024	682,200.00
TOTAL		-	38,221.0	0.0	1,925.0	36,296.0	3.645	3.645	1,323,100.00
Mar-00	VARIOUS	EMER.	10,446.0	0.0	6,328.0	4,118.0	5.250	5.250	216,200.00
	HPP	IPP	24,983.0	0.0	0.0	24,983.0	3.148	3.148	786,400.00
	VARIOUS	OTHER	21,056.0	0.0	0.0	21,056.0	3.059	3.059	644,100.00
TOTAL		-	56,485.0	0.0	6,328.0	50,157.0	3.283	3.283	1,646,700.00
Apr-00	VARIOUS	EMER.	28,383.0	0.0	15,993.0	12,390.0	5.250	5.250	650,500.00
	HPP	IPP	58,917.0	0.0	0.0	58,917.0	2.854	2.854	1,681,600.00
	VARIOUS	OTHER	2,560.0	0.0	0.0	2,560.0	2.336	2.336	59,800.00
TOTAL		-	89,860.0	0.0	15,993.0	73,867.0	3.238	3.238	2,391,900.00
May-00	VARIOUS	EMER.	22,171.0	0.0	12,730.0	9,441.0	16.059	16.059	1,516,100.00
	HPP	IPP	93,789.0	0.0	0.0	93,789.0	2.727	2.727	2,557,300.00
	VARIOUS	OTHER	20,608.0	0.0	0.0	20,608.0	2.750	2.750	566,700.00
TOTAL		-	136,568.0	0.0	12,730.0	123,838.0	3.747	3.747	4,640,100.00
Jun-00	VARIOUS	EMER.	19,513.0	0.0	11,978.0	7,535.0	16.060	16.060	1,210,100.00
	HPP	IPP	116,416.0	0.0	0.0	116,416.0	2.760	2.760	3,213,500.00
	VARIOUS	OTHER	21,350.0	0.0	0.0	21,350.0	3.778	3.778	806,500.00
TOTAL		-	157,279.0	0.0	11,978.0	145,301.0	3.599	3.599	5,230,100.00
Jul-00	VARIOUS	EMER.	28,868.0	0.0	16,002.0	12,866.0	16.059	16.059	2,066,100.00
	HPP	IPP	126,423.0	0.0	0.0	126,423.0	2.769	2.769	3,500,600.00
	VARIOUS	OTHER	22,060.0	0.0	0.0	22,060.0	3.721	3.721	820,800.00
TOTAL		-	177,351.0	0.0	16,002.0	161,349.0	3.959	3.959	6,387,500.00
Aug-00	VARIOUS	EMER.	25,809.0	0.0	14,551.0	11,258.0	16.060	16.060	1,808,000.00
	HPP	IPP	123,708.0	0.0	0.0	123,708.0	2.763	2.763	3,418,000.00
	VARIOUS	OTHER	24,102.0	0.0	0.0	24,102.0	3.721	3.721	896,900.00
TOTAL		-	173,619.0	0.0	14,551.0	159,068.0	3.849	3.849	6,122,900.00
Sep-00	VARIOUS	EMER.	14,494.0	0.0	8,515.0	5,979.0	16.060	16.060	960,200.00
	HPP	IPP	118,506.0	0.0	0.0	118,506.0	2.805	2.805	3,324,300.00
	VARIOUS	OTHER	22,118.0	0.0	0.0	22,118.0	2.756	2.756	609,500.00
TOTAL		-	155,118.0	0.0	8,515.0	146,603.0	3.338	3.338	4,894,000.00
Oct-00	VARIOUS	EMER.	15,243.0	0.0	9,343.0	5,900.0	6.395	6.395	377,300.00
	HPP	IPP	25,533.0	0.0	0.0	25,533.0	3.441	3.441	878,500.00
	VARIOUS	OTHER	4,224.0	0.0	0.0	4,224.0	2.334	2.334	98,600.00
TOTAL		-	45,000.0	0.0	9,343.0	35,657.0	3.798	3.798	1,354,400.00
Nov-00	VARIOUS	EMER.	8,808.0	0.0	5,124.0	3,684.0	6.395	6.395	235,600.00
	HPP	IPP	14,621.0	0.0	0.0	14,621.0	3.924	3.924	573,700.00
	VARIOUS	OTHER	3,520.0	0.0	0.0	3,520.0	2.335	2.335	82,200.00
TOTAL		-	26,949.0	0.0	5,124.0	21,825.0	4.085	4.085	891,500.00
Dec-00	VARIOUS	EMER.	1,128.0	0.0	671.0	457.0	7.374	7.374	33,700.00
	HPP	IPP	19,264.0	0.0	0.0	19,264.0	4.559	4.559	878,300.00
	VARIOUS	OTHER	4,032.0	0.0	0.0	4,032.0	2.334	2.334	94,100.00
TOTAL		-	24,424.0	0.0	671.0	23,753.0	4.236	4.236	1,006,100.00
Jan-00	VARIOUS	EMER.	182,775.0	0.0	105,321.0	77,454.0	12.079	12.079	9,355,800.00
THRU	HPP	IPP	748,154.0	0.0	0.0	748,154.0	2.933	2.933	21,942,300.00
Dec-00	VARIOUS	OTHER	192,070.0	0.0	0.0	192,070.0	3.169	3.169	6,087,100.00
TOTAL		-	1,122,999.0	0.0	105,321.0	1,017,678.0	3.674	3.674	37,385,200.00

SCHEDULE E8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	cents/KWH (A) FUEL COST	cents/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
Jan-00	VARIOUS	CO-GEN.	33,049.0	0.0	0.0	33,049.0	1.723	1.723	569,300.00
Feb-00	VARIOUS	CO-GEN.	31,530.0	0.0	0.0	31,530.0	1.692	1.692	533,600.00
Mar-00	VARIOUS	CO-GEN.	31,813.0	0.0	0.0	31,813.0	1.851	1.851	588,800.00
Apr-00	VARIOUS	CO-GEN.	33,678.0	0.0	0.0	33,678.0	2.246	2.246	756,500.00
May-00	VARIOUS	CO-GEN.	35,005.0	0.0	0.0	35,005.0	2.461	2.461	861,500.00
Jun-00	VARIOUS	CO-GEN.	33,875.0	0.0	0.0	33,875.0	2.489	2.489	843,200.00
Jul-00	VARIOUS	CO-GEN.	36,671.0	0.0	0.0	36,671.0	2.658	2.658	974,800.00
Aug-00	VARIOUS	CO-GEN.	36,671.0	0.0	0.0	36,671.0	2.620	2.620	960,600.00
Sep-00	VARIOUS	CO-GEN.	35,488.0	0.0	0.0	35,488.0	2.503	2.503	888,400.00
Oct-00	VARIOUS	CO-GEN.	35,819.0	0.0	0.0	35,819.0	2.386	2.386	854,500.00
Nov-00	VARIOUS	CO-GEN.	33,595.0	0.0	0.0	33,595.0	2.187	2.187	734,600.00
Dec-00	VARIOUS	CO-GEN.	34,715.0	0.0	0.0	34,715.0	1.900	1.900	659,500.00
TOTAL			411,909.0	0.0	0.0	411,909.0	2.240	2.240	9,225,300.00

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2000 THRU DECEMBER 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (4)X(5)	COST IF GENERATED (A) cents/KWH	COST IF GENERATED (B) ($000'S)	FUEL SAVINGS (7B)-(6)
Jan-00	VARIOUS	ECON.	6,965.0	3.724	259,400.00	4.886	340,300.00	80,900.00
Feb-00	VARIOUS	ECON.	4,861.0	3.573	173,700.00	4.618	224,500.00	50,800.00
Mar-00	VARIOUS	ECON.	10,307.0	3.765	388,100.00	4.723	486,800.00	98,700.00
Apr-00	VARIOUS	ECON.	12,640.0	4.260	538,500.00	5.406	683,300.00	144,800.00
May-00	VARIOUS	ECON.	36,334.0	3.550	1,289,900.00	4.645	1,687,700.00	397,800.00
Jun-00	VARIOUS	ECON.	17,945.0	4.201	753,800.00	5.287	948,800.00	195,000.00
Jul-00	VARIOUS	ECON.	25,225.0	4.055	1,022,800.00	5.153	1,299,800.00	277,000.00
Aug-00	VARIOUS	ECON.	32,087.0	3.807	1,221,600.00	4.924	1,580,100.00	358,500.00
Sep-00	VARIOUS	ECON.	20,085.0	4.475	898,800.00	5.557	1,116,200.00	217,400.00
Oct-00	VARIOUS	ECON.	22,299.0	4.519	1,007,800.00	5.661	1,262,300.00	254,500.00
Nov-00	VARIOUS	ECON.	18,864.0	4.053	764,500.00	5.045	951,700.00	187,200.00
Dec-00	VARIOUS	ECON.	4,442.0	3.733	165,800.00	4.527	201,100.00	35,300.00
TOTAL		-	212,054.0	4.001	8,484,700.00	5.085	10,782,600.00	2,297,900.00

SCHEDULE E10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD* OF: JANUARY 2000 THRU DECEMBER 2000

		Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	TOTAL
BASE RATE REVENUES	($)	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92	51.92
FUEL RECOVERY REVENUES	($)	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59	22.59
CONSERVATION REVENUES	($)	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
CAPACITY REVENUES	($)	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71	2.71
ENVIRONMENTAL REVENUES	($)	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31
DEFERRED REVENUE REFUND	($)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)	(1.52)
FL. GROSS REC. TAX REVENUES	($)	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
TOTAL REVENUES	($)	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27	80.27

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

SCHEDULE E2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JANUARY 1999 THRU DECEMBER 1999

LINE NUMBER		(a) ACTUAL JAN. 99	(b) FEB. 99	(c) MAR. 99	(d) APR. 99	(e) MAY 99	(f) JUNE 99	(g) JULY 99	(h) AUG. 99	(i) ESTIMATED SEPT. 99	(j) OCT. 99	(k) NOV. 99	(l) DEC. 99	TOTAL PERIOD	LINE NUMBER
1	FUEL COST OF SYSTEM NET GENERATION	25,576,800	20,861,862	20,668,049	25,471,536	26,935,229	27,572,523	34,615,520	34,678,741	32,066,631	27,873,425	22,816,685	26,877,121	326,014,142	1
1a	NUCLEAR FUEL DISPOSAL	0	0	0	0	0	0	0	0	0	0	0	0	0	1a
2	FUEL COST OF POWER SOLD *	659,730	409,285	389,382	1,109,128	910,132	1,251,421	1,650,430	1,720,686	1,932,900	1,261,900	792,180	1,067,020	13,174,172	2
3	FUEL COST OF PURCHASED POWER	1,663,944	1,409,272	2,973,084	7,997,043	5,786,581	6,427,746	7,347,098	11,352,741	2,476,900	1,808,200	1,349,000	839,300	51,230,909	3
3a	DEMAND & NON FUEL COST OF PUR POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	3a
3b	QUALIFYING FACILITIES	643,900	592,142	721,993	933,508	1,157,625	772,850	648,194	711,449	823,500	679,300	640,200	587,600	8,912,261	3b
4	ENERGY COST OF ECONOMY PURCHASES	0	0	0	0	0	0	0	(15,402)	412,600	243,300	310,000	120,900	1,071,398	4
4a	ADJUSTMENTS TO FUEL COSTS (FT. MEADE / WAUCHULA WHEELING)	(3,863)	(3,412)	(3,605)	(4,206)	(4,442)	(3,798)	(4,313)	(4,507)	(4,000)	(4,000)	(4,000)	(4,000)	(48,146)	4a
4b	ADJUSTMENTS TO FUEL COSTS	(606,674)	(606,801)	(606,863)	(606,864)	(607,036)	(607,277)	(607,579)	(607,751)	(606,674)	(606,674)	(606,674)	(606,673)	(7,283,540)	4b
5	TOTAL FUEL & NET POWER TRANSACTION (SUM OF LINES 1 THRU 4b)	26,614,377	21,843,798	23,363,276	32,681,891	32,357,825	32,910,623	40,348,490	44,394,605	33,236,057	28,531,651	23,713,031	26,727,228	366,722,852	5
6	JURISDICTIONAL KWH SOLD (MWH)	1,275,517	1,103,597	1,114,374	1,160,503	1,257,285	1,419,058	1,484,514	1,534,220	1,569,571	1,398,242	1,210,130	1,210,554	15,717,565	6
6a	JURISDICTIONAL % OF TOTAL SALES	0.9897173	0.9925353	0.9866973	0.9672632	0.9786640	0.9702618	0.9609319	0.9543163	0.9813069	0.9871537	0.9913979	0.9912832	-	6a
6b	JURISDIC. TOT. FUEL & NET PWR. TRANS. (LINE 5 X LINE 6a)	26,340,711	21,680,740	23,052,481	31,611,990	31,602,723	31,931,911	38,772,149	42,366,495	32,614,772	28,165,125	23,509,049	26,494,252	358,142,398	6b
7	JURISDICTIONAL LOSS MULTIPLIER	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	-	7
7a	LINE 6b x LINE 7	26,358,823	21,695,483	23,068,157	31,633,486	31,624,213	31,953,625	38,796,514	42,395,304	32,636,950	28,184,277	23,525,035	26,512,268	356,385,935	7a
7b	PEABODY COAL CONTRACT BUY-OUT AMORT.	406,337	403,806	404,275	398,744	396,213	393,682	391,151	388,621	386,090	383,559	381,028	378,497	4,712,003	7b
7c	PEABODY JURISDICTIONALIZED (LINE 7b x LINE 6a)	402,159	400,792	398,897	385,690	386,967	381,975	375,869	370,867	378,673	378,632	377,750	375,198	4,813,669	7c
7d	ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	7d
8	JURISDIC. TOT. FUEL & NET PWR. TRANS. INCL. PEABODY & FUEL CREDIT DIFF. (LINE 7a+7c+7d)	26,760,782	22,096,275	23,467,054	32,019,176	32,011,180	32,335,600	39,174,383	42,766,171	33,015,623	28,562,909	23,902,785	26,887,466	362,999,604	8
9	COST PER KWH SOLD (cents/KWH)	2.0980	2.0022	2.1059	2.7591	2.5461	2.2787	2.6749	2.7875	2.1035	2.0428	1.9752	2.2211	2.3095	9
10	TRUE UP ** (cents/KWH)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	(0.0836)	10
11	TOTAL (LINES 9+10)(cents/KWH)	2.0144	1.9186	2.0223	2.6755	2.4625	2.1951	2.5913	2.7039	2.0199	1.9592	1.8916	2.1375	2.2259	11
12	REVENUE TAX FACTOR	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	12
13	RECOVERY FAC. ADJ. FOR TAXES (c/KWH) (EXCL. GPIF)	2.0159	1.9200	2.0238	2.6774	2.4643	2.1967	2.5932	2.7058	2.0214	1.9606	1.8930	2.1390	2.2275	13
14	GPIF ** (cents/KWH) (ALREADY ADJUSTED FOR TAXES)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	(0.0012)	14
15	TOTAL RECOVERY FACTOR (LINES 13+14)	2.0147	1.9188	2.0226	2.6762	2.4631	2.1955	2.5920	2.7046	2.0202	1.9594	1.8918	2.1378	2.2263	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 cents/KWH	2.015	1.919	2.023	2.676	2.463	2.196	2.592	2.705	2.020	1.959	1.892	2.138	2.226	16

* INCLUDES ECONOMY SALES PROFITS (80%)
** BASED ON JURISDICTIONAL SALES ONLY

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 1999 THRU JUNE 1999

		ACTUAL					
		JAN. 99	FEB. 99	MAR. 99	APR. 99	MAY 99	JUNE 99
	FUEL COST OF SYSTEM NET GENERATION ($)						
1	HEAVY OIL	105,613	129,463	153,426	949,335	962,047	1,169,133
2	LIGHT OIL	487,272	217,438	321,358	2,173,430	809,412	1,043,872
3	COAL	24,983,915	20,514,981	20,193,265	22,348,771	25,163,770	25,359,518
4	NATURAL GAS	0	0	0	0	0	0
5	NUCLEAR	0	0	0	0	0	0
6	OTHER	0	0	0	0	0	0
7	TOTAL ($)	25,576,800	20,861,882	20,668,049	25,471,536	26,935,229	27,572,523
	SYSTEM NET GENERATION (MWH)						
8	HEAVY OIL	2,544	3,164	3,943	30,952	26,901	32,891
9	LIGHT OIL	21,337	3,721	11,701	62,548	18,976	35,120
10	COAL	1,199,941	1,048,371	1,015,684	1,097,747	1,233,080	1,341,595
11	NATURAL GAS	0	0	0	0	0	0
12	NUCLEAR	0	0	0	0	0	0
13	OTHER	0	0	0	0	0	0
14	TOTAL (MWH)	1,223,822	1,055,256	1,031,328	1,191,247	1,278,957	1,409,606
	UNITS OF FUEL BURNED						
15	HEAVY OIL (BBL)	7,217	9,230	10,814	69,392	66,564	75,223
16	LIGHT OIL (BBL)	27,898	13,270	18,510	113,752	38,828	50,641
17	COAL (TON)	571,133	488,829	474,571	540,154	606,073	615,200
18	NATURAL GAS (MCF)	0	0	0	0	0	0
19	NUCLEAR (MMBTU)	0	0	0	0	0	0
20	OTHER	0	0	0	0	0	0
	BTUS BURNED (MMBTU)						
21	HEAVY OIL	45,526	58,262	68,225	438,253	420,732	475,045
22	LIGHT OIL	162,124	77,452	107,823	664,094	225,772	294,200
23	COAL	12,688,539	10,864,447	10,360,112	11,612,460	13,281,727	14,064,850
24	NATURAL GAS	0	0	0	0	0	0
25	NUCLEAR	0	0	0	0	0	0
26	OTHER	0	0	0	0	0	0
27	TOTAL (MMBTU)	12,896,189	11,000,161	10,536,160	12,714,807	13,928,231	14,834,095
	GENERATION MIX (% MWH)						
28	HEAVY OIL	0.21	0.30	0.38	2.60	2.10	2.33
29	LIGHT OIL	1.74	0.35	1.13	5.25	1.48	2.49
30	COAL	98.05	99.35	98.49	92.15	96.42	95.18
31	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
32	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST PER UNIT						
35	HEAVY OIL ($/BBL)	14.63	14.03	14.19	13.68	14.45	15.54
36	LIGHT OIL ($/BBL)	17.47	16.39	17.36	19.11	20.85	20.61
37	COAL ($/TON)	43.74	41.97	42.55	41.37	41.52	41.22
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)						
41	HEAVY OIL	2.32	2.22	2.25	2.17	2.29	2.46
42	LIGHT OIL	3.01	2.81	2.98	3.27	3.59	3.55
43	COAL	1.97	1.89	1.95	1.92	1.89	1.80
44	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
45	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL ($/MMBTU)	1.98	1.90	1.96	2.00	1.93	1.86
	BTU BURNED PER KWH (BTU/KWH)						
48	HEAVY OIL	17,895	18,414	17,303	14,159	15,640	14,443
49	LIGHT OIL	7,598	20,815	9,215	10,617	11,898	8,377
50	COAL	10,574	10,363	10,200	10,578	10,771	10,484
51	NATURAL GAS	0	0	0	0	0	0
52	NUCLEAR	0	0	0	0	0	0
53	OTHER	0	0	0	0	0	0
54	TOTAL (BTU/KWH)	10,538	10,424	10,216	10,674	10,890	10,524
	GENERATED FUEL COST PER KWH (cents/KWH)						
55	HEAVY OIL	4.15	4.09	3.89	3.07	3.58	3.55
56	LIGHT OIL	2.28	5.84	2.75	3.47	4.27	2.97
57	COAL	2.08	1.96	1.99	2.04	2.04	1.89
58	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00
59	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL (cents/KWH)	2.09	1.98	2.00	2.14	2.11	1.96

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JULY 1999 THRU DECEMBER 1999

		ACTUAL		ESTIMATED				
		JULY 99	AUG. 99	SEPT. 99	OCT. 99	NOV. 99	DEC. 99	TOTAL
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	1,335,955	1,166,519	399,624	212,971	139,267	60,034	6,783,387
2	LIGHT OIL	1,643,844	1,251,698	580,646	536,286	542,430	578,863	10,186,549
3	COAL	31,635,721	32,260,524	31,086,361	27,124,168	22,134,988	26,238,224	309,044,206
4	NATURAL GAS	0	0	0	0	0	0	0
5	NUCLEAR	0	0	0	0	0	0	0
6	OTHER	0	0	0	0	0	0	0
7	TOTAL ($)	34,615,520	34,678,741	32,066,631	27,873,425	22,816,685	26,877,121	326,014,142
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	38,352	27,722	9,221	4,842	3,173	1,390	185,095
9	LIGHT OIL	41,532	24,864	15,932	14,791	15,461	16,234	282,217
10	COAL	1,521,603	1,547,402	1,544,341	1,359,099	1,152,760	1,303,199	15,364,822
11	NATURAL GAS	0	0	0	0	0	0	0
12	NUCLEAR	0	0	0	0	0	0	0
13	OTHER	0	0	0	0	0	0	0
14	TOTAL (MWH)	1,601,487	1,599,988	1,569,494	1,378,732	1,171,394	1,320,823	15,832,134
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	88,557	69,663	23,885	12,717	8,318	3,581	445,161
16	LIGHT OIL (BBL)	78,941	53,064	24,016	22,308	22,863	24,379	488,470
17	COAL (TON)	748,486	750,487	709,465	617,077	522,219	598,748	7,242,442
18	NATURAL GAS (MCF)	0	0	0	0	0	0	0
19	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20	OTHER	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)							
21	HEAVY OIL	559,431	442,999	150,976	80,380	52,574	22,635	2,815,038
22	LIGHT OIL	457,558	307,868	139,570	129,396	132,497	141,291	2,839,645
23	COAL	16,721,979	17,013,130	16,211,230	14,193,756	12,029,750	13,711,750	162,753,730
24	NATURAL GAS	0	0	0	0	0	0	0
25	NUCLEAR	0	0	0	0	0	0	0
26	OTHER	0	0	0	0	0	0	0
27	TOTAL (MMBTU)	17,738,968	17,763,997	16,501,776	14,403,532	12,214,821	13,875,676	168,408,413
	GENERATION MIX (% MWH)							
28	HEAVY OIL	2.39	1.73	0.59	0.35	0.27	0.11	1.17
29	LIGHT OIL	2.59	1.55	1.02	1.07	1.32	1.23	1.78
30	COAL	95.02	96.72	98.39	98.58	98.41	98.66	97.05
31	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST PER UNIT							
35	HEAVY OIL ($/BBL)	15.09	16.75	16.73	16.75	16.74	16.76	15.24
36	LIGHT OIL ($/BBL)	20.82	23.59	24.18	24.04	23.73	23.74	20.85
37	COAL ($/TON)	42.27	42.99	43.82	43.96	42.39	43.82	42.67
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	2.39	2.63	2.65	2.65	2.65	2.65	2.41
42	LIGHT OIL	3.59	4.07	4.16	4.14	4.09	4.10	3.59
43	COAL	1.89	1.90	1.92	1.91	1.84	1.91	1.90
44	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL ($/MMBTU)	1.95	1.95	1.94	1.94	1.87	1.94	1.94
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	14,587	15,980	16,373	16,601	16,569	16,284	15,209
49	LIGHT OIL	11,017	12,382	8,760	8,748	8,570	8,703	10,062
50	COAL	10,990	10,995	10,497	10,444	10,436	10,522	10,593
51	NATURAL GAS	0	0	0	0	0	0	0
52	NUCLEAR	0	0	0	0	0	0	0
53	OTHER	0	0	0	0	0	0	0
54	TOTAL (BTU/KWH)	11,077	11,103	10,514	10,447	10,428	10,506	10,637
	GENERATED FUEL COST PER KWH (cents/KWH)							
55	HEAVY OIL	3.48	4.21	4.33	4.40	4.39	4.32	3.66
56	LIGHT OIL	3.96	5.03	3.64	3.63	3.51	3.57	3.61
57	COAL	2.08	2.08	2.01	2.00	1.92	2.01	2.01
58	NATURAL GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL (cents/KWH)	2.16	2.17	2.04	2.02	1.95	2.03	2.06

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 1999 THRU JUNE 1999

		ACTUAL					
	HEAVY OIL	JAN. 99	FEB. 99	MAR. 99	APR. 99	MAY 99	JUNE 99
1	PURCHASES:						
2	UNITS (BBL)	2	0	899	9,694	108,648	85,781
3	UNIT COST ($/BBL)	7,440.00	0.00	14.75	16.48	15.48	16.03
4	AMOUNT ($)	14,880	0	13,264	159,761	1,681,824	1,374,927
5	BURNED:						
6	UNITS (BBL)	7,217	9,230	10,814	69,392	66,564	75,223
7	UNIT COST ($/BBL)	14.63	14.03	14.19	13.68	14.45	15.54
8	AMOUNT ($)	105,613	129,463	153,426	949,335	962,047	1,169,133
9	ENDING INVENTORY:						
10	UNITS (BBL)	173,254	164,024	154,110	94,412	136,496	147,054
11	UNIT COST ($/BBL)	13.39	13.38	13.36	13.52	14.64	15.06
12	AMOUNT ($)	2,320,289	2,194,621	2,058,322	1,276,014	1,997,916	2,214,075
13	DAYS SUPPLY:	145	104	63	24	32	48
	LIGHT OIL						
14	PURCHASES:						
15	UNITS (BBL)	53,267	40,707	14,023	146,833	66,061	51,817
16	UNIT COST ($/BBL)	16.86	15.00	19.09	20.08	22.16	19.93
17	AMOUNT ($)	898,335	610,662	267,720	2,947,807	1,463,888	1,032,891
18	BURNED:						
19	UNITS (BBL)	27,898	13,270	18,510	113,752	38,828	50,641
20	UNIT COST ($/BBL)	17.47	16.39	17.36	19.11	20.85	20.61
21	AMOUNT ($)	487,272	217,438	321,358	2,173,430	809,412	1,043,872
22	ENDING INVENTORY:						
23	UNITS (BBL)	55,949	83,165	65,430	88,793	108,752	98,990
24	UNIT COST ($/BBL)	17.23	16.32	16.70	18.96	20.19	19.94
25	AMOUNT ($)	964,040	1,357,290	1,092,356	1,683,242	2,195,497	1,974,289
26	DAYS SUPPLY: NORMAL	54	70	42	48	56	57
27	DAYS SUPPLY: EMERGENCY	8	12	9	13	16	14
	COAL						
28	PURCHASES:						
29	UNITS (TONS)	471,422	652,520	514,975	703,151	364,577	391,436
30	UNIT COST ($/TON)	43.62	42.25	42.29	40.69	43.84	40.35
31	AMOUNT ($)	20,561,530	27,567,390	21,777,196	28,611,791	15,981,728	15,795,408
32	BURNED:						
33	UNITS (TONS)	571,133	488,829	474,571	540,154	606,073	615,200
34	UNIT COST ($/TON)	43.74	41.97	42.55	41.37	41.52	41.22
35	AMOUNT ($)	24,983,915	20,514,981	20,193,265	22,348,771	25,163,770	25,359,518
36	ENDING INVENTORY:						
37	UNITS (TONS)	1,015,402	1,179,093	1,219,497	1,382,494	1,140,998	917,234
38	UNIT COST ($/TON)	42.38	42.20	42.09	41.46	41.93	41.44
39	AMOUNT ($)	43,032,780	49,756,841	51,333,785	57,319,218	47,837,052	38,011,144
40	DAYS SUPPLY:	50	57	56	58	46	38
	NATURAL GAS						
41	PURCHASES:						
42	UNITS (MCF)	0	0	0	0	0	0
43	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT ($)	0	0	0	0	0	0
45	BURNED:						
46	UNITS (MCF)	0	0	0	0	0	0
47	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
48	AMOUNT ($)	0	0	0	0	0	0
49	ENDING INVENTORY:						
50	UNITS (MCF)	0	0	0	0	0	0
51	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52	AMOUNT ($)	0	0	0	0	0	0
53	DAYS SUPPLY:	0	0	0	0	0	0
	NUCLEAR						
54	BURNED:						
55	UNITS (MMBTU)	0	0	0	0	0	0
56	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57	AMOUNT ($)	0	0	0	0	0	0
	OTHER						
58	PURCHASES:						
59	UNITS (MMBTU)	0	0	0	0	0	0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61	AMOUNT ($)	0	0	0	0	0	0
62	BURNED:						
63	UNITS (MMBTU)	0	0	0	0	0	0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65	AMOUNT ($)	0	0	0	0	0	0
66	ENDING INVENTORY:						
67	UNITS (MMBTU)	0	0	0	0	0	0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69	AMOUNT ($)	0	0	0	0	0	0
70	DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING:
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED.
(2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JULY 1999 THRU DECEMBER 1999

		ACTUAL		ESTIMATED				
	HEAVY OIL	JULY 99	AUG. 99	SEPT. 99	OCT. 99	NOV. 99	DEC. 99	TOTAL
1	PURCHASES:							
2	UNITS (BBL)	103,965	82,693	23,885	12,717	8,318	3,581	440,183
3	UNIT COST ($/BBL)	14.76	20.84	16.07	16.93	17.26	16.92	16.60
4	AMOUNT ($)	1,534,501	1,723,499	383,832	215,299	143,569	60,591	7,305,947
5	BURNED:							
6	UNITS (BBL)	88,557	69,663	23,885	12,717	8,318	3,581	445,161
7	UNIT COST ($/BBL)	15.09	16.75	16.73	16.75	16.74	16.76	15.24
8	AMOUNT ($)	1,335,955	1,166,519	399,624	212,971	139,267	60,034	6,783,387
9	ENDING INVENTORY:							
10	UNITS (BBL)	182,462	175,492	175,493	175,493	175,493	175,493	175,493
11	UNIT COST ($/BBL)	14.89	16.96	16.87	16.89	16.92	16.92	16.92
12	AMOUNT ($)	2,419,841	2,977,219	2,960,847	2,964,115	2,968,758	2,969,523	2,969,523
13	DAYS SUPPLY:	102	188	321	949	1,178	614	-
	LIGHT OIL							
14	PURCHASES:							
15	UNITS (BBL)	68,096	102,127	36,734	33,804	34,197	35,972	683,638
16	UNIT COST ($/BBL)	21.97	25.56	23.20	23.60	22.87	23.69	21.37
17	AMOUNT ($)	1,495,780	2,610,559	852,096	797,745	781,962	852,100	14,611,545
18	BURNED:							
19	UNITS (BBL)	78,941	53,064	24,016	22,308	22,863	24,379	488,470
20	UNIT COST ($/BBL)	20.82	23.59	24.16	24.04	23.73	23.74	20.85
21	AMOUNT ($)	1,643,844	1,251,698	580,646	536,286	542,430	578,863	10,186,549
22	ENDING INVENTORY:							
23	UNITS (BBL)	74,234	110,358	110,358	110,358	110,358	110,358	110,358
24	UNIT COST ($/BBL)	20.75	23.55	23.38	23.36	23.19	23.26	23.26
25	AMOUNT ($)	1,540,341	2,599,124	2,580,180	2,578,401	2,559,091	2,566,629	2,566,629
26	DAYS SUPPLY: NORMAL	50	93	101	97	99	102	-
27	DAYS SUPPLY: EMERGENCY	11	16	16	16	16	16	-
	COAL							
28	PURCHASES:							
29	UNITS (TONS)	482,882	823,730	774,000	613,000	565,000	615,861	6,972,554
30	UNIT COST ($/TON)	43.47	41.71	43.99	42.20	42.91	43.83	42.57
31	AMOUNT ($)	20,989,314	34,358,105	34,049,540	25,866,800	24,244,677	26,993,575	296,797,054
32	BURNED:							
33	UNITS (TONS)	748,486	750,487	709,465	617,077	522,219	598,748	7,242,442
34	UNIT COST ($/TON)	42.27	42.99	43.82	43.96	42.39	43.82	42.67
35	AMOUNT ($)	31,635,721	32,260,524	31,086,361	27,124,168	22,134,988	26,238,224	309,044,206
36	ENDING INVENTORY:							
37	UNITS (TONS)	651,630	724,873	807,683	803,606	846,387	863,500	863,500
38	UNIT COST ($/TON)	41.86	41.65	43.17	42.38	43.19	43.65	43.65
39	AMOUNT ($)	27,280,397	30,192,493	34,866,693	34,054,814	36,553,761	37,695,136	37,695,136
40	DAYS SUPPLY:	28	34	40	42	43	43	-
	NATURAL GAS							
41	PURCHASES:							
42	UNITS (MCF)	0	0	0	0	0	0	0
43	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT ($)	0	0	0	0	0	0	0
45	BURNED:							
46	UNITS (MCF)	0	0	0	0	0	0	0
47	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	AMOUNT ($)	0	0	0	0	0	0	0
49	ENDING INVENTORY:							
50	UNITS (MCF)	0	0	0	0	0	0	0
51	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	AMOUNT ($)	0	0	0	0	0	0	0
53	DAYS SUPPLY:	0	0	0	0	0	0	-
	NUCLEAR							
54	BURNED:							
55	UNITS (MMBTU)	0	0	0	0	0	0	0
56	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58	PURCHASES:							
59	UNITS (MMBTU)	0	0	0	0	0	0	0
60	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	AMOUNT ($)	0	0	0	0	0	0	0
62	BURNED:							
63	UNITS (MMBTU)	0	0	0	0	0	0	0
64	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	AMOUNT ($)	0	0	0	0	0	0	0
66	ENDING INVENTORY:							
67	UNITS (MMBTU)	0	0	0	0	0	0	0
68	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69	AMOUNT ($)	0	0	0	0	0	0	0
70	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING:
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED.
(2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD OF: JANUARY 1999 THRU JUNE 1999

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) cents/KWH (A) FUEL COST	(7) cents/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST $ (6)X(7B)	(10) 80% GAIN ON ECONOMY ENERGY SALES
ACTUAL Jan. 99	VARIOUS		ECON.	5,922.0	0.0	5,922.0	1.664	1.802	98,559.04	106,705.97	6,517.54
	VARIOUS	JURISD.	SCH. -D	5,306.0	9.9	5,296.1	1.591	1.591	84,264.57	84,264.57	
	VARIOUS	SEPARATED	SCH. -D	20,112.0	0.0	20,112.0	1.545	1.766	310,785.03	355,115.27	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	9,312.0	0.0	9,312.0	1.990	2.566	185,287.36	238,902.84	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	50.0	0.0	50.0	1.996	1.996	998.20	998.20	
	LESS TRANSMISSION COSTS								(16,792.00)		
	LESS VARIABLE O & M COSTS								(9,889.74)		
	PLUS 80% OF ECON. PROFITS								6,517.54		
TOTAL			-	118,822.0	78,129.9	40,692.1	1.621	1.932	659,730.00	785,986.85	
ACTUAL Feb. 99	VARIOUS		ECON.	1,894.0	0.0	1,894.0	1.872	2.131	35,452.12	40,362.50	3,928.30
	VARIOUS	JURISD.	SCH. -D	4,706.0	0.0	4,706.0	1.798	1.798	84,609.56	84,609.56	
	VARIOUS	SEPARATED	SCH. -D	12,493.0	0.0	12,493.0	1.697	1.903	212,051.33	237,747.59	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	4,289.0	0.0	4,289.0	2.173	2.853	93,198.82	122,345.45	
	FMPA		SCH. -D	70,560.0	70,560.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(16,792.10)		
	LESS VARIABLE O & M COSTS								(3,162.98)		
	PLUS 80% OF ECON. PROFITS								3,928.30		
TOTAL			-	93,942.0	70,560.0	23,382.0	1.750	2.075	409,285.05	485,065.10	
ACTUAL Mar. 99	VARIOUS		ECON.	2,440.0	0.0	2,440.0	2.041	2.214	49,799.90	54,032.05	3,385.72
	VARIOUS	JURISD.	SCH. -D	4,859.0	0.0	4,859.0	2.125	2.125	103,269.92	103,269.92	
	VARIOUS	SEPARATED	SCH. -D	13,498.0	0.0	13,498.0	1.702	1.912	229,681.12	258,028.85	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	1,334.0	0.0	1,334.0	1.230	2.466	16,409.91	32,900.21	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	358.0	0.0	358.0	2.152	2.152	7,702.82	7,702.82	
	LESS TRANSMISSION COSTS								(16,792.10)		
	LESS VARIABLE O & M COSTS								(4,074.80)		
	PLUS 80% OF ECON. PROFITS								3,385.72		
TOTAL			-	100,609.0	78,120.0	22,489.0	1.731	2.027	389,382.49	455,933.85	
ACTUAL Apr. 99	VARIOUS		ECON.	3,173.0	0.0	3,173.0	1.980	2.338	62,818.25	74,193.27	9,100.02
	VARIOUS	JURISD.	SCH. -D	5,939.0	788.3	5,150.7	(0.121)	(0.121)	(6,206.95)	(6,206.95)	
	VARIOUS	SEPARATED	SCH. -D	17,435.0	0.0	17,435.0	1.649	1.885	287,475.34	328,642.33	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	40,029.0	0.0	40,029.0	1.944	2.651	778,030.63	1,061,142.38	
	FMPA		SCH. -D	75,495.0	75,495.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(16,792.10)		
	LESS VARIABLE O & M COSTS								(5,298.91)		
	PLUS 80% OF ECON. PROFITS								9,100.02		
TOTAL			-	142,071.0	76,283.3	65,787.7	1.686	2.216	1,109,126.28	1,457,771.03	
ACTUAL May 99	VARIOUS		ECON.	3,826.0	0.0	3,826.0	1.995	2.282	76,310.51	87,301.91	8,793.12
	VARIOUS	JURISD.	SCH. -D	6,947.0	1,355.7	5,591.3	1.365	1.365	76,298.29	76,298.29	
	VARIOUS	SEPARATED	SCH. -D	16,264.0	0.0	16,264.0	1.667	1.888	271,182.29	307,024.45	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	23,526.0	0.0	23,526.0	2.101	2.800	494,277.57	658,699.74	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	300.0	0.0	300.0	2.119	2.119	6,355.58	6,355.58	
	LESS TRANSMISSION COSTS								(16,792.10)		
	LESS VARIABLE O & M COSTS								(5,293.03)		
	PLUS 80% OF ECON. PROFITS								8,793.12		
TOTAL			-	128,983.0	79,475.7	49,507.3	1.838	2.294	910,132.23	1,135,679.97	
ACTUAL June 99	VARIOUS		ECON.	421.0	0.0	421.0	2.122	2.770	8,934.61	11,663.65	2,183.24
	VARIOUS	JURISD.	SCH. -D	6,865.0	897.1	5,967.9	2.590	2.590	154,577.57	154,577.57	
	VARIOUS	SEPARATED	SCH. -D	20,119.0	0.0	20,119.0	1.617	1.834	325,422.43	369,040.07	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	30,850.0	0.0	30,850.0	2.191	2.898	675,872.56	894,144.08	
	FMPA		SCH. -D	75,600.0	75,600.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	4,460.0	0.0	4,460.0	2.317	2.317	103,329.27	103,329.27	
	LESS TRANSMISSION COSTS								(18,083.00)		
	LESS VARIABLE O & M COSTS								(815.42)		
	PLUS 80% OF ECON. PROFITS								2,183.24		
TOTAL			-	138,315.0	76,497.1	61,817.9	2.024	2.479	1,251,421.26	1,532,754.64	

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JULY 1999 THRU DECEMBER 1999

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) cents/KWH (A) FUEL COST	(7) cents/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST $ (6)X(7B)	(10) 80% GAIN ON ECONOMY ENERGY SALES
ACTUAL	VARIOUS		ECON.	1,232.0	0.0	1,232.0	2.598	3.328	32,010.23	40,999.03	7,191.04
July 99	VARIOUS	JURISD.	SCH. -D	6,733.0	963.9	5,769.1	1.283	1.283	73,996.23	73,996.23	
	VARIOUS	SEPARATED	SCH. -D	20,903.0	0.0	20,903.0	1.665	1.877	348,020.80	392,438.95	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	49,208.0	0.0	49,208.0	2.049	2.679	1,008,409.90	1,318,448.56	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	5,293.0	0.0	5,293.0	3.858	3.858	204,192.64	204,192.64	
	LESS TRANSMISSION COSTS								(21,050.49)		
	LESS VARIABLE O & M COSTS								(2,340.16)		
	PLUS 80% OF ECON. PROFITS								7,191.04		
TOTAL			-	161,489.0	79,083.9	82,405.1	2.003	2.464	1,650,430.19	2,030,075.41	
ACTUAL	VARIOUS		ECON.	1,138.0	0.0	1,138.0	2.301	2.544	26,181.57	28,945.59	2,211.22
Aug. 99	VARIOUS	JURISD.	SCH. -D	6,683.0	1,909.8	4,773.2	(0.899)	(0.899)	(42,932.76)	(42,932.76)	
	VARIOUS	SEPARATED	SCH. -D	21,491.0	0.0	21,491.0	1.651	1.879	354,911.85	403,916.11	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	47,567.0	0.0	47,567.0	2.384	3.033	1,134,228.12	1,442,757.44	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	8,128.0	0.0	8,128.0	3.279	3.279	266,506.78	266,506.78	
	LESS TRANSMISSION COSTS								(18,083.80)		
	LESS VARIABLE O & M COSTS								(2,356.86)		
	PLUS 80% OF ECON. PROFITS								2,211.22		
TOTAL			-	163,127.0	80,029.8	83,097.2	2.071	2.526	1,720,666.12	2,099,193.16	
ESTIMATED	VARIOUS		ECON.	15,792.0	0.0	15,792.0	2.050	2.715	323,700.00	428,700.00	84,000.00
Sept. 99	VARIOUS	JURISD.	SCH. -D	5,840.0	0.0	5,840.0	1.991	1.991	116,300.00	116,300.00	
	VARIOUS	SEPARATED	SCH. -D	23,976.0	0.0	23,976.0	1.718	1.967	411,900.00	471,700.00	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	39,600.0	0.0	39,600.0	2.314	5.280	916,300.00	2,091,000.00	
	FMPA		SCH. -D	75,600.0	75,600.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	5,760.0	0.0	5,760.0	2.391	2.391	137,700.00	137,700.00	
	LESS TRANSMISSION COSTS								(24,500.00)		
	LESS VARIABLE O & M COSTS								(32,500.00)		
	PLUS 80% OF ECON. PROFITS								84,000.00		
TOTAL			-	166,568.0	75,600.0	90,968.0	2.125	3.568	1,932,900.00	3,245,400.00	
ESTIMATED	VARIOUS		ECON.	30,002.0	0.0	30,002.0	2.257	3.005	677,100.00	901,600.00	179,600.00
Oct. 99	VARIOUS	JURISD.	SCH. -D	5,864.0	0.0	5,864.0	1.893	1.893	111,000.00	111,000.00	
	VARIOUS	SEPARATED	SCH. -D	21,056.0	0.0	21,056.0	1.712	1.974	360,500.00	415,700.00	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	600.0	0.0	600.0	2.267	5.233	13,600.00	31,400.00	
	FMPA		SCH. -D	78,120.0	78,120.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(18,100.00)		
	LESS VARIABLE O & M COSTS								(61,800.00)		
	PLUS 80% OF ECON. PROFITS								179,600.00		
TOTAL			-	135,642.0	78,120.0	57,522.0	2.194	2.538	1,261,900.00	1,459,700.00	
ESTIMATED	VARIOUS		ECON.	8,519.0	0.0	8,519.0	2.311	3.111	196,900.00	265,000.00	54,480.00
Nov. 99	VARIOUS	JURISD.	SCH. -D	5,762.0	0.0	5,762.0	1.843	1.843	106,200.00	106,200.00	
	VARIOUS	SEPARATED	SCH. -D	20,376.0	0.0	20,376.0	1.735	2.001	353,500.00	407,700.00	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	4,600.0	0.0	4,600.0	2.537	5.502	116,700.00	253,100.00	
	FMPA		SCH. -D	75,600.0	75,600.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(18,100.00)		
	LESS VARIABLE O & M COSTS								(17,500.00)		
	PLUS 80% OF ECON. PROFITS								54,480.00		
TOTAL			-	114,857.0	75,600.0	39,257.0	2.018	2.629	792,180.00	1,032,000.00	
ESTIMATED	VARIOUS		ECON.	10,963.0	0.0	10,963.0	1.965	2.675	215,400.00	293,300.00	62,320.00
Dec. 99	VARIOUS	JURISD.	SCH. -D	5,775.0	0.0	5,775.0	1.797	1.797	103,800.00	103,800.00	
	VARIOUS	SEPARATED	SCH. -D	21,056.0	0.0	21,056.0	1.726	1.993	363,900.00	419,700.00	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	16,700.0	0.0	16,700.0	2.289	5.256	382,300.00	877,700.00	
	FMPA		SCH. -D	95,400.0	95,400.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	LESS TRANSMISSION COSTS								(18,100.00)		
	LESS VARIABLE O & M COSTS								(22,600.00)		
	PLUS 80% OF ECON. PROFITS								62,320.00		
TOTAL			-	149,894.0	95,400.0	54,494.0	1.995	3.110	1,087,020.00	1,694,500.00	
Jan. 99	VARIOUS		ECON.	85,322.0	0.0	85,322.0	2.113	2.734	1,803,166.23	2,332,803.97	423,710.20
THRU	VARIOUS	JURISD.	SCH. -D	71,279.0	5,924.7	65,354.3	1.477	1.477	965,176.43	965,176.43	
Dec. 99	VARIOUS	SEPARATED	SCH. -D	228,779.0	0.0	228,779.0	1.674	1.909	3,829,330.19	4,366,753.62	
	VARIOUS	JURISD.	SCH. -G	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	HPP	SEPARATED	CONTRACT	267,615.0	0.0	267,615.0	2.173	3.371	5,814,614.87	9,022,540.70	
	FMPA		SCH. -D	936,975.0	936,975.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	SCH. -J	24,349.0	0.0	24,349.0	2.985	2.985	726,785.29	726,785.29	
	LESS TRANSMISSION COSTS								(219,977.69)		
	LESS VARIABLE O & M COSTS								(168,631.90)		
	PLUS 80% OF ECON. PROFITS								423,710.20		
TOTAL			-	1,614,319.0	942,899.7	671,419.3	1.962	2.594	13,174,173.62	17,414,060.01	

SCHEDULE E7

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JANUARY 1999 THRU DECEMBER 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	cents/KWH (A) FUEL COST	cents/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
ACTUAL JAN. 99	VARIOUS	EMER.	21,829.0	0.0	845.6	20,983.4	2.914	2.914	611,522.84
	HPP	IPP	23,200.0	0.0	0.0	23,200.0	4.536	4.536	1,052,421.34
	PECO	OTHER	54,094.0	54,094.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,029.0	24,029.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	123,152.0	78,123.0	845.6	44,183.4	3.766	3.766	1,663,944.18
ACTUAL FEB. 99	VARIOUS	EMER.	11,496.0	0.0	0.0	11,496.0	2.221	2.221	255,278.95
	HPP	IPP	62,226.0	0.0	0.0	62,226.0	1.855	1.855	1,153,993.12
	PECO	OTHER	48,860.0	48,860.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	21,700.0	21,700.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	144,282.0	70,560.0	0.0	73,722.0	1.912	1.912	1,409,272.07
ACTUAL MAR. 99	VARIOUS	EMER.	7,532.0	0.0	0.0	7,532.0	3.001	3.001	226,022.00
	HPP	IPP	155,788.0	0.0	0.0	155,788.0	1.763	1.763	2,747,062.46
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	241,440.0	78,120.0	0.0	163,320.0	1.820	1.820	2,973,084.46
ACTUAL APR. 99	VARIOUS	EMER.	145,169.0	0.0	32,405.2	112,763.8	6.032	6.032	6,801,907.73
	HPP	IPP	51,427.0	0.0	0.0	51,427.0	2.324	2.324	1,195,135.65
	PECO	OTHER	52,295.0	52,295.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	23,200.0	23,200.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	272,091.0	75,495.0	32,405.2	164,190.8	4.871	4.871	7,997,043.38
ACTUAL MAY 99	VARIOUS	EMER.	111,620.0	0.0	17,513.3	94,106.7	3.751	3.751	3,529,644.84
	HPP	IPP	90,656.0	0.0	0.0	90,656.0	2.490	2.490	2,256,935.75
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	280,396.0	78,120.0	17,513.3	184,762.7	3.132	3.132	5,786,580.59
ACTUAL JUNE 99	VARIOUS	EMER.	134,627.0	0.0	25,130.8	109,496.2	3.836	3.836	4,199,991.26
	HPP	IPP	76,053.0	0.0	0.0	76,053.0	2.929	2.929	2,227,755.02
	PECO	OTHER	52,350.0	52,350.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	286,280.0	75,600.0	25,130.8	185,549.2	3.464	3.464	6,427,746.28
ACTUAL JULY 99	VARIOUS	EMER.	97,733.0	0.0	24,123.7	73,609.3	5.488	5.488	4,039,459.08
	HPP	IPP	98,515.0	0.0	0.0	98,515.0	3.357	3.358	3,307,639.12
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	274,368.0	78,120.0	24,123.7	172,124.3	4.268	4.268	7,347,098.20
ACTUAL AUG. 99	VARIOUS	EMER.	139,237.0	0.0	45,909.6	93,327.4	7.832	7.832	7,309,210.99
	HPP	IPP	133,580.0	0.0	0.0	133,580.0	3.027	3.027	4,043,529.80
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	350,937.0	78,120.0	45,909.6	226,907.4	5.003	5.003	11,352,740.79
ESTIMATED SEPT. 99	VARIOUS	EMER.	8,733.0	0.0	5,385.0	3,348.0	15.565	15.565	521,100.00
	HPP	IPP	56,603.0	0.0	0.0	56,603.0	2.782	2.782	1,574,600.00
	VARIOUS	OTHER	14,310.0	0.0	0.0	14,310.0	2.664	2.664	381,200.00
	PECO	OTHER	52,350.0	52,350.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	155,246.0	75,600.0	5,385.0	74,261.0	3.335	3.335	2,476,900.00
ESTIMATED OCT. 99	VARIOUS	EMER.	3,285.0	0.0	2,261.0	1,024.0	6.191	6.191	63,400.00
	HPP	IPP	43,192.0	0.0	0.0	43,192.0	2.834	2.834	1,223,900.00
	VARIOUS	OTHER	12,432.0	0.0	0.0	12,432.0	2.581	2.581	320,900.00
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	137,029.0	78,120.0	2,261.0	56,648.0	2.839	2.839	1,608,200.00
ESTIMATED NOV. 99	VARIOUS	EMER.	5,901.0	0.0	3,382.0	2,519.0	6.197	6.197	156,100.00
	HPP	IPP	28,511.0	0.0	0.0	28,511.0	3.062	3.062	873,100.00
	VARIOUS	OTHER	12,320.0	0.0	0.0	12,320.0	2.596	2.596	319,800.00
	PECO	OTHER	52,350.0	52,350.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	23,250.0	23,250.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	122,332.0	75,600.0	3,382.0	43,350.0	3.112	3.112	1,349,000.00
ESTIMATED DEC. 99	VARIOUS	EMER.	1,081.0	0.0	666.0	415.0	7.133	7.133	29,600.00
	HPP	IPP	9,958.0	0.0	0.0	9,958.0	4.601	4.601	458,200.00
	VARIOUS	OTHER	13,616.0	0.0	0.0	13,616.0	2.582	2.582	351,500.00
	PECO	OTHER	54,095.0	54,095.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	24,025.0	24,025.0	0.0	0.0	0.000	0.000	0.00
	FPL	OTHER	17,280.0	17,280.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	120,055.0	95,400.0	666.0	23,989.0	3.499	3.499	839,300.00
JAN. 99 THRU DEC. 99	VARIOUS	EMER.	688,243.0	0.0	157,622.2	530,620.8	5.228	5.228	27,743,237.69
	HPP	IPP	829,709.0	0.0	0.0	829,709.0	2.665	2.665	22,114,272.26
	VARIOUS	OTHER	52,678.0	0.0	0.0	52,678.0	2.607	2.607	1,373,400.00
	PECO	OTHER	636,869.0	636,869.0	0.0	0.0	0.000	0.000	0.00
	FPC	OTHER	282,829.0	282,829.0	0.0	0.0	0.000	0.000	0.00
	FPL	OTHER	17,280.0	17,280.0	0.0	0.0	0.000	0.000	0.00
TOTAL		-	2,507,608.0	936,978.0	157,622.2	1,413,007.8	3.626	3.626	51,230,909.95

SCHEDULE E8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JANUARY 1999 THRU DECEMBER 1999

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	cents/KWH (A) FUEL COST	cents/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
ACTUAL	JAN. 99	VARIOUS	CO-GEN.	36,501.0	0.0	34.0	36,467.0	1.766	1.766	643,900.33
ACTUAL	FEB. 99	VARIOUS	CO-GEN.	31,285.0	0.0	0.0	31,285.0	1.893	1.893	592,141.94
ACTUAL	MAR. 99	VARIOUS	CO-GEN.	37,044.0	0.0	0.0	37,044.0	1.949	1.949	721,993.34
ACTUAL	APR. 99	VARIOUS	CO-GEN.	43,583.0	0.0	3,070.0	40,513.0	2.304	2.304	933,507.54
ACTUAL	MAY 99	VARIOUS	CO-GEN.	39,833.0	0.0	(1,831.3)	41,664.3	2.778	2.778	1,157,625.26
ACTUAL	JUNE 99	VARIOUS	CO-GEN.	38,964.0	0.0	1,523.0	37,441.0	2.064	2.064	772,850.07
ACTUAL	JULY 99	VARIOUS	CO-GEN.	33,378.0	0.0	1,405.5	31,972.5	2.027	2.027	648,193.54
ACTUAL	AUG. 99	VARIOUS	CO-GEN.	32,001.0	0.0	1,550.0	30,451.0	2.336	2.336	711,448.70
ESTIMATED	SEPT. 99	VARIOUS	CO-GEN.	35,159.0	0.0	0.0	35,159.0	2.342	2.342	823,500.00
ESTIMATED	OCT. 99	VARIOUS	CO-GEN.	35,679.0	0.0	0.0	35,679.0	1.904	1.904	679,300.00
ESTIMATED	NOV. 99	VARIOUS	CO-GEN.	34,055.0	0.0	0.0	34,055.0	1.880	1.880	640,200.00
ESTIMATED	DEC. 99	VARIOUS	CO-GEN.	35,190.0	0.0	0.0	35,190.0	1.670	1.670	587,600.00
	TOTAL			432,672.0	0.0	5,751.2	426,920.8	2.088	2.088	8,912,260.72

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD OF: JANUARY 1999 THRU DECEMBER 1999

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT (4)X(5)	COST IF GENERATED (A) cents/KW	COST IF GENERATED (B) ($000'S)	FUEL SAVINGS (7B)-(6)
ACTUAL	JAN. 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	FEB. 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	MAR. 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	APR. 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	MAY 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	JUNE 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	JULY 99	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	AUG. 99	VARIOUS	ECON.	14.0	(110.014)	(15,401.97)	(109.760)	(15,366.41)	35.56
ESTIMATED	SEPT. 99	VARIOUS	ECON.	9,586.0	4.304	412,600.00	5.414	519,000.00	106,400.00
ESTIMATED	OCT. 99	VARIOUS	ECON.	5,809.0	4.188	243,300.00	5.225	303,500.00	60,200.00
ESTIMATED	NOV. 99	VARIOUS	ECON.	7,521.0	4.122	310,000.00	5.176	389,300.00	79,300.00
ESTIMATED	DEC. 99	VARIOUS	ECON.	3,093.0	3.909	120,900.00	4.960	153,400.00	32,500.00
	TOTAL			26,023.0	4.117	1,071,398.03	5.187	1,349,833.59	278,435.56

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY

SCHEDULE H1

		PERIOD OF : JANUARY THRU DECEMBER				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL 1997	ACTUAL 1998	ACT/EST 1999	EST 2000	1997/98%	1998/99%	1999/00%
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	*HEAVY OIL	7,878,252	7,669,418	6,783,387	9,324,336	-2.7%	-11.6%	37.5%
2	*LIGHT OIL	8,351,407	8,127,091	10,186,549	8,108,619	-2.7%	25.3%	-20.4%
3	COAL	349,167,754	339,247,903	309,044,206	342,201,626	-2.8%	-8.9%	10.7%
4	NATURAL GAS	0	0	0	807,276	0.0%	0.0%	0.0%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	TOTAL ($)	365,397,413	355,044,412	326,014,142	360,441,857	-2.8%	-8.2%	10.6%
	SYSTEM NET GENERATION (MWH)							
8	*HEAVY OIL	186,185	210,755	185,095	214,875	12.0%	-12.2%	16.1%
9	*LIGHT OIL	202,323	228,184	282,217	210,854	12.8%	23.7%	-25.3%
10	COAL	17,343,420	16,735,445	15,364,822	17,497,408	-3.5%	-8.2%	13.9%
11	NATURAL GAS	0	0	0	20,592	0.0%	0.0%	0.0%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL (MWH)	17,733,928	17,174,384	15,832,134	17,943,729	-3.2%	-7.8%	13.3%
	UNITS OF FUEL BURNED							
15	*HEAVY OIL (BBL)	423,518	467,673	445,161	538,350	10.4%	-4.8%	20.9%
16	*LIGHT OIL (BBL)	319,057	401,108	488,470	289,010	25.7%	21.8%	-40.8%
17	COAL (TON)	8,130,607	7,892,962	7,242,442	7,919,993	-2.9%	-8.2%	9.4%
18	NATURAL GAS (MCF)	0	0	0	293,500	0.0%	0.0%	0.0%
19	NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20	OTHER	0	0	0	0	0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)							
21	*HEAVY OIL	2,676,725	2,951,709	2,815,038	3,402,913	10.3%	-4.6%	20.9%
22	*LIGHT OIL	1,863,485	2,323,777	2,839,645	1,952,656	24.7%	22.2%	-31.2%
23	COAL	184,048,011	176,095,960	162,753,730	181,654,454	-4.3%	-7.6%	11.6%
24	NATURAL GAS	0	0	0	302,213	0.0%	0.0%	0.0%
25	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26	OTHER	0	0	0	0	0.0%	0.0%	0.0%
27	TOTAL (MMBTU)	188,588,221	181,371,446	168,408,413	187,312,236	-3.8%	-7.1%	11.2%
	GENERATION MIX (% MWH)							
28	*HEAVY OIL	1.06	1.23	1.17	1.20	-	-	-
29	*LIGHT OIL	1.14	1.33	1.78	1.18	-	-	-
30	COAL	97.80	97.44	97.05	97.51	-	-	-
31	NATURAL GAS	0.00	0.00	0.00	0.11	-	-	-
32	NUCLEAR	0.00	0.00	0.00	0.00	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	*HEAVY OIL ($/BBL)	18.60	16.40	15.24	17.32	-11.8%	-7.1%	13.6%
36	*LIGHT OIL ($/BBL)	26.18	20.26	20.85	28.06	-22.6%	2.9%	34.6%
37	COAL ($/TON)	42.94	42.98	42.67	43.21	0.1%	-0.7%	1.3%
38	NATURAL GAS ($/MCF)	0.00	0.00	0.00	2.75	0.0%	0.0%	0.0%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)							
41	*HEAVY OIL	2.94	2.60	2.41	2.74	-11.6%	-7.3%	13.7%
42	*LIGHT OIL	4.48	3.50	3.59	4.15	-21.9%	2.6%	15.6%
43	COAL	1.90	1.93	1.90	1.88	1.6%	-1.6%	-1.1%
44	NATURAL GAS	0.00	0.00	0.00	2.67	0.0%	0.0%	0.0%
45	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	TOTAL ($/MMBTU)	1.94	1.96	1.94	1.92	1.0%	-1.0%	-1.0%
	BTU BURNED PER KWH (BTU/KWH)							
48	*HEAVY OIL	14,224	14,005	15,209	15,837	-1.5%	8.6%	4.1%
49	*LIGHT OIL	9,210	10,184	10,062	9,261	10.6%	-1.2%	-8.0%
50	COAL	10,612	10,522	10,593	10,382	-0.8%	0.7%	-2.0%
51	NATURAL GAS	0	0	0	14,676	0.0%	0.0%	0.0%
52	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53	OTHER	0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL (BTU/KWH)	10,634	10,561	10,637	10,439	-0.7%	0.7%	-1.9%
	GENERATED FUEL COST PER KWH (cents/KWH)							
55	*HEAVY OIL	4.19	3.64	3.66	4.34	-13.1%	0.5%	18.6%
56	*LIGHT OIL	4.13	3.56	3.61	3.85	-13.8%	1.4%	6.6%
57	COAL	2.01	2.03	2.01	1.96	1.0%	-1.0%	-2.5%
58	NATURAL GAS	0.00	0.00	0.00	3.92	0.0%	0.0%	0.0%
59	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL (cents/KWH)	2.06	2.07	2.06	2.01	0.5%	-0.5%	-2.4%

* DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ – 2)
DOCUMENT NO. 2
FILED: 10/01/99

Residential Bill for 1000 kwh			
Type of Charge	**Jan 99 - Dec 99**	**Jan 00- June 00**	**June 00 - Dec 00**
Customer	$8.50	$8.50	$8.50
Energy	$43.42	$43.42	$43.42
Conservation	$1.32	$1.25	$1.25
Environmental	$0.28	$1.35	$1.35
Fuel	$22.30	$22.59	$22.59
Capacity	$2.06	$2.71	$2.71
Subtotal	**$77.88**	**$79.82**	**$79.82**
Deferred Revenue Refund	N/A	($1.52)	$0.00
FGR Tax	$2.00	$2.01	$2.01
Total	**$79.88**	**$80.31**	**$81.83**

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
SUBMITTED FOR FILING 10/01/99

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
PROJECTED
JANUARY 2000 - DECEMBER 2000

TAMPA ELECTRIC COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2000 THROUGH DECEMBER 2000

	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (mWh)	(3) Projected AVG 12 CP at Meter (mW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (mWh)	(7) Projected AVG 12 CP at Generation (mW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS	52.72%	7,289,825	1,578	1.06163	1.06230	7,743,959	1,675	44.08%	59.25%
GS,TS	63.02%	980,928	178	1.06190	1.06230	1,042,037	189	5.93%	6.69%
GSD, EV-X	78.24%	4,481,070	654	1.06033	1.06124	4,755,491	693	27.07%	24.51%
GSLD,SBF	86.13%	1,909,482	253	1.04515	1.04521	1,995,815	264	11.36%	9.34%
IS-1&3,SBI-1&3	N/A	1,812,066	N/A	N/A	1.02121	1,850,502	0	10.53%	0.00%
SL/OL	329.52%	170,634	6	1.05882	1.06230	181,264	6	1.03%	0.21%
TOTAL		16,644,004	2,669			17,569,068	2,827	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 1997 calendar data.
(2) Projected mWh sales for the period Jan. 2000 through Dec. 2000.
(3) Calculated: Col(2)/(8760*Col(1)).
(4) Based on 1997 demand losses.
(5) Based on 1997 energy losses.
(6) Col(2)*Col(5)
(7) Col(3)*Col(4)
(8) Col(6) / total for Col(6).
(9) Col(7) / total for Col(7).

NOTE: Interruptible rates not included in demand allocation of capacity payments.

EXHIBIT NO.____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
PAGE 1 OF 5

TAMPA ELECTRIC COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2000 THROUGH DECEMBER 2000

	JANUARY	FEBRUARY	PROJECTED MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. UNIT POWER CAPACITY CHARGES	$1,421,400	$1,421,400	$1,412,400	$1,332,900	$1,545,400	$2,396,500	$2,771,500	$2,771,500	$1,811,500	$1,646,500	$1,640,500	$1,646,500	$21,818,000
2. CAPACITY PAYMENTS TO COGENERATORS	920,900	920,900	920,900	943,700	943,700	943,700	943,700	943,700	943,700	943,700	943,700	943,700	11,256,000
3. (UNIT POWER CAPACITY REVENUES)	(93,800)	(92,700)	(92,400)	(81,500)	(85,300)	(80,600)	(77,100)	(76,900)	(79,300)	(86,300)	(87,600)	(91,300)	(1,024,800)
4. SYSTEM TOTAL	$2,248,500	$2,249,600	$2,240,900	$2,195,100	$2,403,800	$3,259,600	$3,638,100	$3,638,300	$2,675,900	$2,503,900	$2,496,800	$2,498,900	$32,049,200
5. JURISDICTIONAL PERCENTAGE	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	-
6. JURISDICTIONAL CAPACITY PAYMENTS	$2,207,942	$2,209,022	$2,200,479	$2,155,505	$2,360,440	$3,200,804	$3,572,476	$3,572,673	$2,627,632	$2,458,735	$2,451,567	$2,453,825	$31,471,100
7. ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 1999 - DEC. 1999 OVER/(UNDER) RECOVERY													2,487,804
8. TOTAL													$33,958,904
9. REVENUE TAX FACTOR													1.00072
10. TOTAL RECOVERABLE CAPACITY PAYMENTS													$33,983,354

CALCULATION OF JURISDICTIONAL %

	1997 AVG 12 CP MW	%
FPSC	15,803.6	98.19621%
FERC	290.3	1.80379%
TOTAL	16,093.9	100.00000%

EXHIBIT NO. ____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
PAGE 2 OF 5

TAMPA ELECTRIC COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2000 THROUGH DECEMBER 2000

RATE CLASS	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Capacity Recovery Factor ($/kwh)
RS	44.08%	59.25%	1,151,951	18,586,746	19,738,697	7,289,824,778	0.00271
GS,TS	5.93%	6.69%	154,970	2,098,655	2,253,625	980,928,118	0.00230
GSD,EV-X	27.07%	24.51%	707,426	7,688,795	8,396,221	4,481,069,894	0.00187
GSLD,SBF	11.36%	9.34%	296,873	2,929,961	3,226,834	1,909,481,690	0.00169
IS-1&3,SBI-1&3	10.53%	0.00%	275,183	0	275,183	1,812,065,891	0.00015
SL/OL	1.03%	0.21%	26,917	65,877	92,794	170,634,000	0.00054
					33,983,354		
TOTAL	100.00%	100.00%	2,613,320	31,370,034	33,983,354	16,644,004,371	0.00204
			7.69% *	92.31% *			

* NOTE: Using the 12 CP and 1/13th allocation method requires 1/13th or 7.69 % of capacity costs to be allocated on the basis of energy, and 12/13th or 92.31 % to be allocated on the basis of demand.

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
PAGE 3 OF 5

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/PROJECTED TRUE-UP AMOUNT

	ACTUAL JAN. 1999	ACTUAL FEB.1999	ACTUAL MAR. 1999	ACTUAL APRIL 1999	ACTUAL MAY 1999	ACTUAL JUNE 1999	ACTUAL JULY 1999	ACTUAL AUG. 1999	PROJECTED SEPT. 1999	PROJECTED OCT. 1999	PROJECTED NOV. 1999	PROJECTED DEC. 1999	TOTAL 1999
1. UNIT POWER CAPACITY CHARGES	$1,126,091	$1,126,091	$1,126,091	$1,220,122	$1,202,658	$1,504,841	$1,609,251	$1,654,091	$1,300,900	$1,266,400	$1,266,400	$1,343,600	$15,746,536
2. CAPACITY PAYMENTS TO COGENERATORS	1,133,595	1,107,710	1,081,825	1,133,595	1,133,595	1,133,595	1,133,595	891,020	891,000	891,000	891,000	891,000	12,312,530
3. (UNIT POWER CAPACITY REVENUES)	(99,052)	(89,944)	(77,292)	(113,114)	(97,613)	(112,355)	(107,885)	(65,597)	(148,200)	(86,400)	(86,000)	(91,500)	(1,176,932)
4. TOTAL CAPACITY CHARGES - CURRENT PERIOD	$2,160,634	$2,143,857	$2,130,624	$2,240,603	$2,238,640	$2,526,081	$2,634,961	$2,479,514	$2,043,700	$2,071,000	$2,069,400	$2,143,100	$26,882,134
5. JURISDICTIONAL PERCENTAGE	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	98.19621%	-
6. JURISDICTIONAL CAPACITY PAYMENTS	$2,121,661	$2,105,186	$2,092,192	$2,200,187	$2,198,260	$2,480,516	$2,587,451	$2,434,789	$2,006,836	$2,033,644	$2,032,072	$2,104,443	$26,397,237
7. CAPACITY COST RECOVERY REVENUES (NET OF REVENUE TAXES)	$1,993,172	$1,684,336	$1,681,797	$1,842,370	$1,952,893	$2,264,526	$2,370,143	$2,550,719	$2,531,178	$2,196,419	$1,833,680	$1,845,671	$24,746,904
8. PRIOR PERIOD TRUE-UP PROVISION	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,952)	(97,948)	(1,175,420)
9. CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (NET OF REVENUE TAXES)	$1,895,220	$1,586,384	$1,583,845	$1,744,418	$1,854,941	$2,166,574	$2,272,191	$2,452,767	$2,433,226	$2,098,467	$1,735,728	$1,747,723	$23,571,484
10. TRUE-UP PROVISION FOR MONTH - OVER/(UNDER) RECOVERY (LINE 9 - LINE 6)	($226,441)	($518,802)	($508,347)	($455,769)	($343,319)	($313,942)	($315,260)	$17,978	$426,390	$64,823	($296,344)	($356,720)	($2,625,753)
11. INTEREST PROVISION FOR MONTH	(3,226)	(4,330)	(6,053)	(7,595)	(8,819)	(10,050)	(11,252)	(11,813)	(10,982)	(9,760)	(9,974)	(11,196)	(105,050)
12. TRUE-UP & INTEREST PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(1,175,420)	(1,307,135)	(1,732,315)	(2,148,763)	(2,514,175)	(2,768,361)	(2,994,401)	(3,222,961)	(3,118,844)	(2,605,484)	(2,452,469)	(2,660,835)	(28,701,163)
13. DEFERRED TRUE-UP - OVER/(UNDER) RECOVER	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999	442,999
14. PRIOR PERIOD TRUE-UP PROVISION - COLLECTED/(REFUNDED) THIS MONTH	97,952	97,952	97,952	97,952	97,952	97,952	97,952	97,952	97,952	97,952	97,952	97,948	1,175,420
15. END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	($864,136)	($1,289,316)	($1,705,764)	($2,071,176)	($2,325,362)	($2,551,402)	($2,779,962)	($2,675,845)	($2,162,485)	($2,009,470)	($2,217,838)	($2,487,804)	($2,487,804)

EXHIBIT NO.____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
PAGE 4 OF 5

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/PROJECTED TRUE-UP AMOUNT

	ACTUAL JAN. 1999	ACTUAL FEB.1999	ACTUAL MAR. 1999	ACTUAL APRIL 1999	ACTUAL MAY 1999	ACTUAL JUNE 1999	ACTUAL JULY 1999	ACTUAL AUG. 1999	PROJECTED SEPT. 1999	PROJECTED OCT. 1999	PROJECTED NOV. 1999	PROJECTED DEC. 1999	TOTAL
1. BEGINNING TRUE-UP AMOUNT	(732,421)	(864,136)	(1,289,316)	(1,705,764)	(2,071,176)	(2,325,362)	(2,551,402)	(2,779,962)	(2,675,845)	(2,162,485)	(2,009,470)	(2,217,836)	N/A
2. ENDING TRUE-UP AMOUNT BEFORE INTEREST	(860,910)	(1,284,966)	(1,699,711)	(2,063,581)	(2,316,543)	(2,541,352)	(2,768,710)	(2,664,032)	(2,151,503)	(1,999,710)	(2,207,862)	(2,476,608)	N/A
3. TOTAL BEGINNING & ENDING TRUE-UP AMOUNT (LINES 1 + 2)	(1,593,331)	(2,149,122)	(2,989,027)	(3,769,345)	(4,387,719)	(4,866,714)	(5,320,112)	(5,443,994)	(4,827,348)	(4,162,195)	(4,217,332)	(4,694,444)	N/A
4. AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(796,666)	(1,074,561)	(1,494,514)	(1,884,673)	(2,193,860)	(2,433,357)	(2,660,056)	(2,721,997)	(2,413,674)	(2,081,098)	(2,108,666)	(2,347,222)	N/A
5. INT. RATE % - FIRST DAY REP. BUS. MONTH	4.900	4.810	4.850	4.880	4.800	4.850	5.050	5.100	5.320	5.600	5.650	5.700	N/A
6. INT. RATE % - FIRST DAY SUBSEQUENT MONTH	4.810	4.850	4.880	4.800	4.850	5.050	5.100	5.320	5.600	5.650	5.700	5.750	N/A
7. TOTAL (LINE 5 + LINE 6)	9.710	9.660	9.730	9.680	9.650	9.900	10.150	10.420	10.920	11.250	11.350	11.450	N/A
8. AVERAGE INT. RATE % (50% OF LINE 7)	4.855	4.830	4.865	4.840	4.825	4.950	5.075	5.210	5.460	5.625	5.675	5.725	N/A
9. MONTHLY AVG. INT. RATE % (LINE 8/12)	0.405	0.403	0.405	0.403	0.402	0.413	0.423	0.434	0.455	0.469	0.473	0.477	N/A
10. INT. PROVISION (LINE 4 X LINE 9)	($3,226)	($4,330)	($6,053)	($7,595)	($8,819)	($10,050)	($11,252)	($11,813)	($10,982)	($9,760)	($9,974)	($11,196)	($105,050)

EXHIBIT NO.____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ-3)
PAGE 5 OF 5

EXHIBIT NO._____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(KOZ - 4)
FILED: 10/01/99

Tampa Electric Company

Deferred Revenue Plan Refund
January 2000 Through December 2000

	Beginning Balance $	Projected Retail Sales MWH	Projected Revenue $	Ending Balance $
Jan-00				
Feb-00	$11,821,901	1,340,065	$2,022,295	$9,799,606
Mar-00	$9,799,606	1,212,891	$1,830,377	$7,969,229
Apr-00	$7,969,229	1,195,727	$1,804,475	$6,164,754
May-00	$6,164,754	1,217,471	$1,837,288	$4,327,466
Jun-00	$4,327,466	1,344,317	$2,028,712	$2,298,754
Total Jan - Jun	$2,298,754	1,523,259	$2,298,754	$0
	$0	7,833,730	$11,821,901	
			0.151	¢/kWh

Refund Adjustment For Variations in Line Loss			
Fuel Group	Average Refund	Line Loss Factor	Group Rate ¢/kWh
Group A: RS, GS, TS	0.151	1.0072	0.152
Group A1: SL, OL	0.151	1.0072	0.152
Group B: SD, GSLD, SB	0.151	1.0013	0.151
Group C: IS, SBI	0.151	0.9687	0.146

EXHIBIT NO. 30
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(TLH-1)
PAGE 1 OF 1

FMPA Wholesale Power Sales Agreement

Net Benefits to Retail Ratepayers
(As of October 1999)

Period	Net Benefits ('97$ x 1000)	
1997 - 1999	$ 9,841	(1)
2000 - 2001	$ ~~3,699~~ 3,406	(2)
Total Net Benefits	$ ~~13,540~~ 13,248	
Original Net Benefits Estimate	$ 9,004	(3)

(1) Actual/estimated impact on deferred revenue refunds due to separation of production and transmission resources from the retail jurisdiction less fuel credits booked as above the line operating revenues per Order No. 970171-EU.

(2) Includes estimated revenues and costs to serve the FMPA contract assuming current projections.

(3) Original estimate provided by Tampa Electric Witness Branick in Document 4 of her prefiled testimony in Docket No. 970171-EU.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 30
COMPANY/
WITNESS: Dumaresq
DATE 11-22-99

EXHIBIT NO. _____

DOCKET NO: 990001-EI

WITNESS: THOMAS L. HERNANDEZ

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT: 1) TAMPA ELECTRIC COMPANY'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 10); 2) TAMPA ELECTRIC COMPANY'S RESPONSE TO LATE-FILED DEPOSITION EXHIBIT NO. 2; AND 3) TAMPA ELECTRIC COMPANY'S RESPONSE TO LATE-FILED DEPOSITION EXHIBIT NO. 5

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 31
COMPANY: PSC Staff
WITNESS:
DATE: 11-22-99

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 1st SET OF INTERROGATORIES
INTERROGATORY NO. 10
SPONSOR: ZWOLAK
PAGE 1 of 1

10. Please provide a table which separately indicates on an annual basis the amount of economy energy that TECO purchased and sold through the EBN from 1990 to 1998.

A. As stated in the response to Interrogatory No. 1.c., TEC does not differentiate between broker and non-broker economy energy transactions. Provided below are the total amounts of economy energy sold and purchased by TEC.

	Economy MWH Sales	Economy MWH Purchases
1990	1,341,964	124,490
1991	1,186,358	15,207
1992	666,170	64,852
1993	1,402,526	140,518
1994	1,378,193	59,426
1995	2,069,566	35,095
1996	2,200,521	63,457
1997	1,658,267	101,048
1998	744,079	10,882

IMPACT OF CURRENT TREATMENT VERSUS PROPOSED TREATMENT ON 1,000 KILOWATT HOUR RESIDENTIAL BILL

The current accounting treatment for the FMPA contract includes the separation of assets at the system average embedded cost and was defined in this Commission's Order No. PSC-97-0262-FOF-EI. In addition, the system incremental costs for fuel and SO_2 are credited through the fuel and environmental recovery clauses. The crediting for these costs is made from above-the-line revenues. The proposed treatment is described in the direct testimony of Thomas L. Hernandez.

The impact of the current treatment for the FMPA contract would result in a higher residential bill than that being proposed for January 1, 2000 through March 15, 2001. The deferred revenue sharing arrangement (which provided the benefits associated with separation during 1997-1999) is no longer in effect and the fuel benefit under the company's proposed treatment would no longer occur since more of the revenues from the contract would be held by the company and placed below-the-line. Attached is a schedule depicting the differences and impact on a 1000 kWh residential bill.

Impact on 1000 kWh Residential Bill
Current and Proposed Treatment for FMPA Contract
($ per 1000 kWh)

	Current FMPA Treatment	Proposed FMPA Treatment	
		Total FMPA Revenues Credited	Less: System Average Fuel & Purchased Power [1]
2000			
Customer	$0.00	$0.00	$0.00
Energy	-	-	-
Conservation	-	-	-
Environment	0.00	(0.12)	0.00
Fuel	0.00	(2.00)	(0.35)
Capacity	-	-	-
Subtotal	0.00	(2.12)	(0.35)
Deferred Revenue Refun	-	-	-
FGR Tax	-	-	-
Total 2000	0.00	(2.12)	(0.35)
2001			
Customer	$0.00	$0.00	$0.00
Energy	-	-	-
Conservation	-	-	-
Environment	0.00	(0.03)	0.00
Fuel	0.00	(0.40)	(0.07)
Capacity	-	-	-
Subtotal	0.00	(0.42)	(0.07)
Deferred Revenue Refun	-	-	-
FGR Tax	-	-	-
Total 2001	0.00	(0.42)	(0.07)

[1] Represents the overall weighted average cost of all units and purchases for fuel and incremental SO2 costs for environmental .

CHECK TO SYSTEM INCREMENTAL COST ATTRIBUTED TO THE FMPA SALE FOR JANUARY 1, 2000 THROUGH MARCH 15, 2001

Incremental Costs of FMPA Sale

January 2000 through March 2001

Fuel (1)	**$**	**33,557,257**
O&M (2)	**$**	**3,390,150**
SO_2 (3)	**$**	**2,558,140**
Total	**$**	**39,505,547**

Notes:

1. The fuel cost is calculated by multiplying the projected system average fuel and purchased power cost (*excluding* GPIF and Peabody contract adjustments) by the FMPA sale energy including transmission losses.

2. The O&M cost is calculated by multiplying the forecasted O&M cost of $2.10/MWH in 2000 and $2.15/MWH in 2001 by the FMPA sale energy including losses.

3. The SO_2 cost is calculated by multiplying the projected weighted average tons of SO_2 (based on generation) of Big Bend Unit 2, Big Bend Unit 3, Gannon Unit 5, and Gannon Unit 6 allocated to the FMPA sale times the forecasted SO_2 allowance cost of $225.54/ton for 2000 and $240.43/ton for 2001.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35b
PAGE 1 of 3

35b. Please list all maintenance activities that TECO, prior to the explosion, expected to be performed on Gannon Unit 6 before the unit could be brought back on-line. Please provide a timeline showing when these maintenance activities would have been performed if the explosion had not occurred.

A. Attached is "Gannon Unit #6 1999 Major Outage Original Plan March 26 through May 23," a list of maintenance activities with completion dates that TECO, prior to the explosion, expected to perform on Gannon Unit 6 before the unit could be brought back on-line.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 32
COMPANY/ WITNESS: Black
DATE: 11-22-99

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35b
PAGE 2 of 3

GANNON UNIT #6 1999 MAJOR OUTAGE
ORIGINAL PLAN*
March 26th through May 23rd

Unit off line	March 26
Boiler cool down	March 27
Open boiler	March 27
Turbine cooldown	April 05
Boiler de-slag	March 27 - March 29
Precipitator wash	March 30 – April 02
Ash removal (hoppers, nose void, penthouse)	March 30 - April 03
Slag tank (inspect)	March 30 – April 03
Remove turbine insulation	April 06
HP turbine disassembly	April 06
Generator disassembly	April 06
Air preheater (unload baskets)	April 06 – April 09
Boiler inspection	April 07
Chip & clean furnace floor	April 07 – April 10
External burner repairs	April 09 – May 18
Main pass pressure wash	April 10 – April 11
Back pass wash	April 10 – April 14
Air preheater (inspect & repair)	April 10 – April ?
Turbine valve disassembly	April 12
Install full boiler scaffold	April 12 - April 17
Slag tank neck replacement	April 14 – May 14
Back pass repairs	April 15 – April 27
First radiant bends replacement	April 18 – May 13
Lower furnace tube repair	April 18 – April 22
Internal burner repairs	April 18 – May 15
Nose arch sandblast	April 23
Sandblast for weld overlay	April 23 – April 25
Vacuum furnace floor	April 26
Install nose void studs	April 27 – May 1
Lower furnace weld overlay	April 27 – May 1
Stud furnace floor	May 02 – May 13
Install generator rotor	May 06
Install HP turbine rotor	May 07
Reassemble reheat stop valves	May 07

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35b
PAGE 3 of 3

Reassemble throttle valves	May 10
Reheat hydro	May 12
Repairs from reheat hydro	May 13
Main steam hydro	May 14
Repairs from main steam hydro	May 14
Seal oil system in service	May 15
Initial generator air test off turning gear	May 15
Slag tank (check out & repair)	May 15 – May 20
Move boiler internal scaffold	May 15 – May 17
Turbine oil flush	May 17
Close boiler for air test	May 17
Boiler air test	May 18
Vacuum & clean debris from furnace floor	May 19
Repairs from boiler air test	May 19 – May 21
Install furnace refractory	May 20
Turbine on turning gear	May 20
Final generator air test	May 20
Install turbine & turbine valve insulation	May 20
Stroke turbine valves	May 20
Install slag tank refractory	May 21
Furnace refractory air cure	May 22 (24 hrs)
Close boiler for service	May 22
Turbine roll on steam	May 22
Unit start up	May 22
Firm load	May 23 (PM)

* This is the original plan and was subject to change as work progresses. In the case of the Generator disassembly, such activity was not to occur until after April 6 due to difficultly in obtaining satisfactory electrical test results.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 1 of 8

35c. Please list all additional maintenance and repair activities, beyond those activities listed in response to Interrogatory No. 35b, that TECO performed due to the explosion to bring Gannon Unit 6 back on-line.

A. Attached is Tampa Electric's – Work Management System: Gannon Incident Related Work (18614 – Opened after 4/8/99). It is a list of additional maintenance and repair activities, beyond those listed in response to Interrogatory No. 35b, that TECO performed due to the explosion to bring Gannon Unit 6 back on-line. This list does not include repairs to other units or additional Gannon Unit 6 repairs not critical to getting Unit 6 back on line.

Work Order	Task	Open Date	Completion Date	Description
1326829	20	04/10/1999	06/02/1999	UNIT 6 VENT FAN ON NORTH WALL NEEDS TO BE SECURED IT HAS BEEN SHAKEN LOOSE FROM THE EXPLOSION
	33	04/10/1999	05/29/1999	TRANSITE CLEANUP - PLEASE CLEANUP ALL TRANSITE FROM IMMIDIATE AREA OF EXPLOSION AND PARKING LOT AREA FOR 5 AND 6 AREAS - 1-4 WILL BE COVERED UNDER TASK-3
	35	04/10/1999	04/23/1999	TURBINE BUILDING VENTILATION DAMPERS -THE TURBINE BUILDING DAMPERS BETWEEN THE 5 AND 6 UNITS ARE DAMAGED . SECURE REPAIR AND REPLACE THE DAMPERS AND DAMPER ACTUATERS . THE ONE CLOSEST TO THE UNIT 6 IS IN DANGER OF FALLING THROUGH THE ROOF TO THE TURBINE DECK.
	38	04/11/1999	04/15/1999	SERVICE AIR LINE - PLEASE FIX THE SERVICE AIR LINE THAT PENETRATES THE EAST WALL ON UNIT 6, IT HAS BEEN SEVERED BY FALLING TRANSITE DURING DURING THE EXPLOSION.
	53	04/11/1999	05/29/1999	UNITS 5& 6 I/O ROOM - EXTENSIVE DAMAGE, INSPECT CLEAN AND REPAIR AS NECESSARY.
	54	04/11/1999	05/19/1999	UNITS 5&6 I/O ROOM - REPAIR AS NECESSARY EQUIPMENT IN THE I/O ROOM . INITIALLY NEED TO GET CONTROL ROOM INDICATION OF UNIT 5 BOILER TUBE METAL AND STEAM DRUM TEMPERATURES.
	57	04/11/1999	05/19/1999	UNIT 5 & 6 UPS ROOM - INSPECT, CLEAN AND REPAIR AS NECESSARY.
	127	04/14/1999	05/26/1999	UNITS #1 THRU #6 PROVIDE MANPOWER TO ASSIST WITH CLEANING OF UNITS # 1 THRU #6 AS NECESSARY.
	128	04/14/1999	05/04/1999	UNITS # 5 & #6 - PROVIDE MANPOWER TO ASSIST WITH CLEAN-UP OF UNITS #5 & # 6 AS NECESSARY.
	134	04/14/1999	05/04/1999	UNIT #6 - PLEASE REPLACE THE EMPTY CO2 BOTTLES WITH FULL BOTTLES. THE NEW BOTTLES ARE LOCATED ON THE GROUND FLOOR UNDER #1 AIR EJECTOR. SET UP TOOLS AND BREAKE THE HOSE FITTINGS FROM THE BOTTLES. rECONNECT THE NEW BOTTLES TO THE MANIFOLD.
	148	04/15/1999	06/02/1999	UNIT #6 A-B-C- PRIMARY AIR FANS - EACH FAN HAS DUST AND DEBRIS ON THE WHEEL & HOUSING THAT NEEDS TO BE CLEANED. VACUUM EACH PRIMARY AIR FAN WHEEL, VEINS AND HOUSING USE HEPA FILTER VACUUM METHOD.
	153	04/16/1999	05/27/1999	UNIT #6 - PROVIDE SERVICES TO CHECK OU_T THE DELUGE SYSTEMS ON TRANSFORMER AND BOILER FEED PUMP. " SERVICES WERE PROVIDED FOR THE CHECK OU_T OF THE SYSTEM AT NO COST"
	154	04/16/1999	06/15/1999	UNIT #6 C PULVERIZER - FIRE PROTECTION PANEL JUST NORTH OF "C" MILL IS IN ALARM. THIS IS THE PANEL FOR THE BFP. THERE IS NO WATER PRESSURE AT THIS PANEL AT THIS TIME. THIS MAY BE WHY IT IS IN ALARM. TROUBLESHOOT AND REPAIR AS NEEDED.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 2 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 2 OF 8

WorkMan- Work Management System

Gannon Incident Related Work (18614 - Opened after 4/8/99)

Work Order	Task	Open Date	Completion Date	Description
1326829	155	04/16/1999	05/24/1999	UNIT #6 TURBINE OIL RESERVOIR - THERE IS A DAMAGED GAUGE ON TOP OF THE TURBINE LUBE OIL TANK. THE GAUGE JUST AS YOU GET TO THE TOP OF THE STAIRS IS BAD. IT IS A 0-160 PSI ASHCROFT. 600-4948.
	157	04/16/1999	04/27/1999	UNIT #6 - REPAIR THE DAMAGED GRATING WEST OF THE GENERATOR.
	158	04/16/1999	04/29/1999	UNIT #6 - REPAIR DAMAGED CHECKER PLATE ON THE NORTHEAST SIDE OF THE TURBINE.
	164	04/17/1999	06/14/1999	UNIT #6 P. A. FAN "B" - SEND MOTOR OU_T TO BE CLEANED AND INSPECTED, REINSTALL WHEN MOTOR IS RETURNED.
	165	04/17/1999	06/08/1999	UNIT #6 P. A. FAN "B" - BREAK MOTOR COUPLING TO ALLOW MOTOR TO BE SENT OU_T FOR INSPECTION. WHEN MOTOR IS RETURNED MAKE ALIGNMENT & MAKE - UP COUPLING.
	166	04/17/1999	06/23/1999	UNIT #6 "B" P. A. FAN - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	167	04/17/1999	06/14/1999	UNIT #6 P. A. FAN "C" - SEND MOTOR OU_T TO BE CLEANED AND INSPECTED. REINSTALL WHEN MOTOR IS RETURNED.
	168	04/17/1999	06/07/1999	UNIT #6 P. A. FAN "C" - BREAK MOTOR COUPLING TO ALLOW MOTOR TO BE SENT OU_T FOR REPAIRS. WHEN MOTOR IS RETURNED MAKE MOTOR ALIGNMENT AND MAKE UP COUPLING.
	169	04/17/1999	06/23/1999	UNIT #6 P. A. FAN "C" - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	170	04/17/1999	06/14/1999	UNIT #6 PULVERIZER MOTOR "A" - SEND MOTOR OU_T TO BE CLEANED AND INSPECTED. INSTALL WHEN WORK IS COMPLETED.
	171	04/17/1999	06/07/1999	UNIT # 6 PULVERIZER MOTOR "A" - BREAK MOTOR COUPLING TO ALLOW MOTOR TO BE SENT OU_T FOR REPAIRS. WHEN MOTOR IS RETURNED MAKE MOTOR ALIGNMENT & MAKE UP COUPLING.
	172	04/17/1999	06/06/1999	UNIT #6 PULVERIZER MOTOR "B" - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	174	04/17/1999	04/27/1999	TURBINE ROOM CRANE - BUILD SCAFFOLD ON THE NORTH END OF THE OVERHEAD CRANE FOR EME TO MAKE ELECTRICAL RAIL REPAIRS. REMOVE SCAFFOLD WHEN REPAIRS HAVE BEEN COMPLETED.
	176	04/17/1999	06/23/1999	TURBINE ROOM CRANE RAILS - REPAIR ELECTRICAL CRANE RAILS OVER #5 & #6 UNITS AS NECESSARY.
	187	04/19/1999	06/04/1999	UNIT #6 TURBINE STEAM LINES - INSPECT (BOROSCOPE) THE INTERNALS OF THE STEAM LINES AT THE TURBINE THAT WERE OPEN AT THE TIME OF THE EXPLOSION. CLEAN OU_T THE LINES AS NECESSARY.
	189	04/19/1999	06/21/1999	UNIT #6 STATOR COOLING PANEL - DAMAGE TO THE STATOR COOLING H2 PANELS.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 3 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 3 OF 8

TECO
TAMPA ELECTRIC

WorkMan- Work Management System

Gannon Incident Related Work (18614 - Opened after 4/8/99)

Work Order	Task	Open Date	Completion Date	Description
1326829	191	04/19/1999	05/25/1999	UNIT #6 4160 SWITCHGEAR - PROVIDE 4 ELECTRICANS TO LABEL AND REMOVE ALL WIRE ON THE 4160 VOLT SWITCHGEAR DOORS.
	193	04/19/1999	05/14/1999	HAVE EQUIPMENT TAGGED OU_T OF SERVICE.UNITS #5 & 6 COOLING TOWERS - THE COVERS FOR THE ACID PUMP RESERVOIRS ARE MISSING. PUMPS NEED FLUSHED , OIL CHANGED . THE COVERS ARE MISSING AND NEED TO BE REPLACED. EL. 9' . WE DO NOT HAVE ANY COVERS IN STOCK. SUGGEST GOING TO FAB SHOP AND SHEARING SOME 1/4" S/S PLATE FOR THE COVERS. THEN CUT AND INSTALL SOME FOAM OR RUBBER GASKET MATERIAL FOR SEAL.
	194	04/19/1999	05/10/1999	UNITS #5 & 6 COOLING TOWERS - THE 2" PVC PROTECTIVE PIPE IS BROKEN AT THE PUMPS DISCHARGE AND THE JUNCTION BOX BEFORE IT GOES VERTICAL UP THE SIDE OF THE BUILDING, ALSO 1/2" POLY TUBING NEEDS REPLACED FROM PUMP DISCHARGE TO THE COOLING TOWERS. REPLACE THE BOWL ON THE EMERGENCY EYE WASH STATION. EL. 9'
	196	04/19/1999	09/10/1999	UNITS #5 & 6 COOLING TOWER ACID PUMPS - LIGHTING OVER THE COOLING TOWER ACID PUMP CONTAINMENT AREA NEEDS REPAIRED/REPLACED. EL9'
	197	04/19/1999	05/10/1999	UNIT #6 COOLING TOWER ACID SYSTEM - REPAIR/REPLACE THE 2" PVC BROKEN AT THE JUNCTION BOX BOTH SIDES, THE 2" PVC BROKEN AT THE TOWER FEED BOX, 2" PVC JUST EAST OF THE JUNCTION BOX HAS DROPPED DOWN CAUSING A SAG IN THE LINE, IT NEEDS TO BE REATTACHED TO BRACES. (THESE REPAIRS ARE LOCATED ON THE TURBINE ROOM ROOF SOU_TH OF #6 COOLING TOWER. ALSO REPAIR/REPLACE THE 2" PVC BROKEN AT THE JUNCTION BOX (THIS JOB IS LOCATED ON THE TURBINE ROOM ROOF BETWEEN #5 & #6 COOLING TOWERS.
	199	04/19/1999	06/17/1999	UNIT #6 - ASSIST PDS AND DUDLEY EAGER AS NECESSARY TO HANDLE, REMOVE & INSTALL NEW OR REBUILT CIRCUIT BREAKERS IN #6 SWITCHGEAR. DETERMINATE WIRES FOR BROKEN RELAYS, RETERMINATE AFTER REPAIRS ARE COMPLETED.
	203	04/20/1999	06/17/1999	UNIT #6 HYDROGEN PANEL - THE ENGRAVED LENSES WERE BLOWN OFF THE TWO ANNUNCIATOR PANELS IN THE HYDROGEN PANEL. PURCHASE REPLACEMENT LENSES AND ANY OTHER COMPONENTS THAT MIGHT HAVE BEEN DAMAGED.FUNCTIONALLY CHECK OU_T PANEL FOR ANY OTHER DAMAGE.
	205	04/20/1999	05/28/1999	UNIT #6 BOILER FEED PUMP/TURBINE ANNUNCIATOR - INSPECT, CLEAN , TEST & REPAIR ANY PROBLEMS FOUND RELATED TO THE EXPLOSION, ALSO REPAIR & CALIBRATE GAUGES & SWITCHES AS PER J. WILLIAMS.
	208	04/20/1999	06/11/1999	UNIT #6 MAIN TURBINE - REPAIR & CALIBRATE INSTRUMENTATION AS NECESSARY (GAUGES & SWITCHES) AS PER J. WILLIAMS
	209	04/20/1999	06/15/1999	UNIT #6 GENERATOR - REPAIR & CALIBRATE INSTRUMENTATION AS NECESSARY (GAUGES & SWITCHES), AS PER J. WILLIAMS
	210	04/20/1999	06/17/1999	UNIT #6 BOILER FEED PUMP TURBINE - REPAIR & CALIBRATE GAUGES & SWITCHES AS NECESSARY AS PER J. WILLIAMS.
	211	04/20/1999	06/17/1999	UNIT #6 GENERATOR HYDROGEN SEAL OIL SYSTEM - REPAIR/ CALIBRATE GAUGES AND SWITCHES ON THE SEAL OIL SYSTEM.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 4 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 4 OF 8

WorkMan- Work Management System

Gannon Incident Related Work (18614 - Opened after 4/8/99)

Work Order	Task	Open Date	Completion Date	Description
1326829	212	04/20/1999	06/17/1999	UNIT #6 GENERATOR STATOR WATER COOLING SYSTEM - REPAIR & CALIBRATE STATOR WATER SYSTEM INSTRUMENTATION GAUGE AND SWITCHES.
	223	04/20/1999	05/06/1999	UNIT #6 A-B-C- PRIMARY AIR FANS - EACH FAN HAS DUST AND DEBRIS ON THE WHEEL & HOUSING THAT NEEDS TO BE CLEANED. VACUUM EACH PRIMARY AIR FAN WHEEL, VEINS AND HOUSING USE HEPA FILTER VACUUM METHOD.
	228	04/21/1999	06/17/1999	# 6 4160 VOLT BREAKERS & #3 4160 V BREAKERS. MOVE THE BREAKERS FROM THE THIRD FLOOR TO THE FIRST FLOOR THERE WILL BE A TRUCK PROVIDED TO TRANSPORT THE BREAKERS. LIFTING RIG IS AT THE ELECTRIC SHOP. USING A FORK LIFT TRANSPORT THE BREAKERS TO THE WAREHOUSE TO BE PLACED INSPECIAL PROJECTS.
	243	04/23/1999	05/24/1999	#6 BOILER IGNITOR CONTROLS - REPAIR/REPLACED DAMAGED IGNITOR CONTROL RELAYS AS NECESSARY TO RETURN SYSTEM TO OPERATION
	251	04/26/1999	09/17/1999	UNIT 6 "A" P. A. FAN MOTOR - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	252	04/26/1999	06/03/1999	UNIT 6C PULV -PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	253	04/26/1999	06/04/1999	UNIT #6 - REPLACE H. P. SHELL INSULATION BLANKETS THAT ARE DAMAGED OR MISSING DUE TO THE INCIDENT.
	254	04/26/1999	09/14/1999	UNIT # 6 PULV. MOTOR "C" - BREAK MOTOR COUPLING TO ALLOW MOTOR TO BE SENT OU_T FOR INSPECTION. WHEN MOTOR IS RETURNED, MAKE ALIGNMENT AND MAKE-UP COUPLING.
	255	04/26/1999	06/07/1999	UNIT #6 "A" P. A. FAN MOTOR - BREAK COUPLING TO ALLOW MOTOR TO BE SENT OU_T FOR INSPECTION. WHEN MOTOR IS RETURNED, MAKE COUPLING ALIGNMENT & MAKE-UP COUPLING.
	265	04/26/1999	05/28/1999	UNIT #6 PULVERIZERS ANNUNCIATOR PANEL - INSPECT , CLEAN , TEST & REPAIR ANY PROBLEMS FOUND RELATED TO THE EXPLOSION.
	266	04/26/1999	06/09/1999	UNIT #6 "A" CONDENSATE PUMP MOTOR - REMOVE MOTOR AND SEND TO T. A. W. FOR INSPECTION/REPAIRS. WHEN MOTOR IS RETURNED REINSTALL ON PUMP.
	267	04/26/1999	06/10/1999	UNIT #6 "A" CONDENSATE PUMP MOTOR - UNLOAD MECH. SEAL & BREAK COUPLING TO ALLOW MOTOR TO BE REMOVED. WHEN MOTOR IS RETURNED ALIGN. MOTOR , MAKE - UP COUPLING AND SET MECH. SEAL.
	268	04/26/1999	06/08/1999	UNIT #6 "A" CONDENSATE PUMP MOTOR - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	269	04/26/1999	06/09/1999	UNIT #6 "B" CONDENSATE PUMP MOTOR - REMOVE MOTOR AND SEND TO T. A. W. FOR INSPECTION/REPAIRS. WHEN MOTOR IS RETURNED, REINSTALL ON PUMP.
	270	04/26/1999	06/14/1999	UNIT #6 "B" CONDENSATE PUMP MOTOR - UNLOAD MECH. SEAL & BREAK COUPLING TO ALLOW MOTOR TO BE REMOVED. WHEN MOTOR IS RETURNED ALIGN. MOTOR, MAKE - UP COUPLING AND SET MECH. SEAL.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 5 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 5 OF 8

Work Order	Task	Open Date	Completion Date	Description
1326829	271	04/26/1999	06/08/1999	UNIT #6 "B" CONDENSATE PUMP MOTOR - PROVIDE SERVICES TO CLEAN & INSPECT MOTOR FOR POSSIBLE DAMAGE.
	305	05/10/1999	06/04/1999	UNITS #5 & #6 HYDROGEN HEADER - HEADER HAS PULLED AWAY FROM THE STRUCTURE ABOVE THE NORTH FLOOD WALL FROM BEHIND #5 TRANSFORMER TO UNIT #6. CUT HOLES IN THE RESILITE SIDING AND REATTACH HEADER SUPPORT BRACKETS AND HEADER TO THE STEEL STRUCTURE. HEADER RUNS FROM BEHIND #5 TRANSFORMER, RUNS EAST ABOVE THE RAILROAD DOOR, CONTINUES BEHIND #6 TRANSFORMER AND PENETRATES BACK THROUGH THE RESILITE WALL AT #6 UNIT. IF FURTHER DETAILS ARE REQUIRED, CONTACT W. CROWLEY EXT. 35-443.
	306	05/10/1999	06/14/1999	UNITS #5 & #6 HYDROGEN HEADER - HEADER HAS PULLED AWAY FROM THE STRUCTURE ABOVE THE NORTH FLOOD WALL FROM BEHIND #5 TRANSFORMER TO UNIT #6. MAKE WELD CONNECTION ON HYDROGEN HEADER SOU_TH OF #5 TRANSFORMER. CUT AND CAP THE HEADER BETWEEN #5 & #6 UNIT TO ALLOW #5 UNIT TO BE CHARGED AND PURGED. IF FURTHER DETAILS ARE NEEDED CONTACT W. CROWLEY AT EXT. 35-443.
	308	05/12/1999	05/13/1999	UNIT #5 & #6 AIR COMPRESSORS - 2 MAJOR PLANT COMPRESSORS HAVE NOT BEEN ABLE TO RUN DUE TO DAMAGES ON THE UNIT #6 POWER DISTRIBUTION EQUIPMENT (WHERE THE COMPRESSORS POWER ORIGINATES FROM) , SINCE ONE OF THESE COMPRESSORS IS NECESSARY TO OPERATE UNIT #5, TEMPORARY FEEDS & EQUIPMENT MUST BE INSTALLED UNTIL REPAIRS ARE COMPLETED. INSTALL & REMOVE AS REQUIRED.
	315	05/18/1999	06/09/1999	#6 GENERATOR ACCESS COVER. PLEASE FABRICATE A NEW ACCESS COVER TO REPLACE THE ONE THAT WAS REMOVED DURING THE EXPLOSION. GANNON MACHINE SHOP TO FABRICATE. SAMPLE COVER TO BE PROVIDED BY S. COMBAST. ALSO, INSTALL ONE THREADED INSERT AS DIRECTED BY SAMCOMBAST AND RETAP ALL BOLT HOLES.
	316	05/19/1999	05/25/1999	#6 GEN VAPOR EXTRACTOR- BREAK COUPLING SO ELECTRIC SHOP CAN REMOVE MOTOR FOR OVERHAUL. MAKE SHAFT ALIGNMENT WHEN MOTOR IS REPLACED.
	317	05/19/1999	06/07/1999	#6 GEN VAPOR EXTRACTOR- OVERHAUL/REPLACE MOTOR THAT WAS DAMAGED IN THE EXPLOSION.
	321	05/22/1999	05/25/1999	UNIT #6 GENERATOR- PLEASE CUT ONE PIECE OF PLATE (1 1/2" THICK) LARGE ENOUGH IN DIAMETER TO FINISH MACHINING TO 20". PLATE IS LOCATED AT PLATE RACK.
	323	05/24/1999	06/12/1999	UNIT #6 - THERE ARE BURNED CABLES IN THE CABLE TRAY ABOVE THE MAIN TRANSFORMER CAUSED BY THE FIRE DURING THE INCIDENT. REMOVE BURNED CABLES AND REPLACE AS REQUIRED. DETERMINE TO & FROM LOCATION AND TERMINATE WIRES. SCAFFOLD WILL BE SET-UP AND LATER REMOVED ON WORKORDER/TASK 1326829-324.

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 6 OF 8

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 6 of 8

Work Order	Task	Open Date	Completion Date	Description
1326829	324	05/24/1999	06/15/1999	UNIT #6 - INSTALL SCAFFOLD UNDER THE MAIN TRANSFORMER CABLE TRAY, WHERE CABLES HAVE BEEN DAMAGED. REMOVE SCAFFOLD WHEN REPAIRS ON WORKORDER/TASK 1326829-323 HAVE BEEN COMPLETED.
	336	06/01/1999	06/12/1999	UNIT #6 - REMOVE & INSTALL #6 A & #6B SUBSTATION 480 VOLT BREAKERS AS REQUIRED. THESE BREAKERS WERE DAMAGED DURING INCIDENT.
	337	06/01/1999	06/12/1999	UNIT #6 - CLEAN & REPAIR #6A & #6B SUBSTATION 480 VOLT BREAKERS AS REQUIRED. THESE BREAKERS WERE DAMAGED DURING INCIDENT. GPR 48159 N66253
	338	06/02/1999	06/17/1999	UNIT #6 L. P. TURBINE - PLEASE CLEAN-UP INSULATION DEBRIS FOUND INSIDE THE LOW PRESS TURBINE SHELL. CONTACT LARRY CHANDLER OR GARY YERTY @ 35-129 FOR ADDITIONAL INFORMATION.
	354	06/09/1999	06/15/1999	NITROGEN HEADER - RESTORE THE NITROGEN LINES FOR THE STATION SERVICE & MAIN TRANSFORMERS THAT WERE DAMAGED DUE TO THE UNIT #6 INCIDENT.
	355	06/10/1999	06/23/1999	#6 STATION SERVICE TRANSFORMER SECONDARY FEEDER CABLES WHICH ARE IN CABLE TRAYS ABOVE THE UNIT , HAVE COME LOOSE (DUE TO THE INCIDENT) IN THE VERTICAL SECTION THUS CREATING A STRAIN THAT COULD DAMAGE THESE CABLES. THESE CABLES NEED TO BE PULLED BACK AND RESUPPORTED WITH TIE-RAPS TO THE VERTICAL TRAY AS REQUIRED.
1329528	1	04/21/1999	06/11/1999	Provide new excitation switchgear - PO N72047
	2	04/23/1999		Provide AC and DC Bus duct sections as required for the new excitation switchgear. PO N 72391 to Powell. Technical assistance during installation also included.
	3	04/23/1999	06/23/1999	Determinate cables and bus work to Unit 6 excitation switchgear. Cables to be taped and pulled down to the cable trays. Bus work to be unbolted, shunt sections removed and flanges (ou_ter enclosure) removed. This work is in preparation to remove the excitation switchgear. Bolting, shunts, flanges and related hardware are to be bagged, identified and saved for reuse. Wiring drawings will be provided by engineering. As a minimum the DC bus section adjacent to the collector housing will be sent ou_t for rework. Remove all sections & related equipment, dispose as directed.
	4	04/27/1999	06/02/1999	UNIT #6 - PROVIDE ASSISTANCE TO E.M.E. FOR REMOVAL OF SWITCHGEAR AS REQUESTED.
	5	04/27/1999	06/18/1999	UNIT #6 - PROVIDE STRUCTURAL SERVICES FOR INSTALLATION OF SUPPORT MODIFICATIONS FOR THE NEW EQUIPMENT.
	6	04/27/1999	05/11/1999	UNIT #6 - PROVIDE ASSISTANCE TO E.M.E. FOR INSTALLATION OF NEW SWITCHGEAR AS MAY BE REQUESTED.
	9	04/27/1999	06/21/1999	UNIT #6 - PROVIDE ELECTRICAL SERVICES TO CHECK-OU_T AND START-UP OF EXCITATION SYSTEM. PROVIDE START UP SUPPORT DURING INITIAL PHASE OF PUTTING UNIT 6 IN SERVICE

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 7 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 7 OF 8

Gannon Incident Related Work (18614 - Opened after 4/8/99)

Work Order	Task	Open Date	Completion Date	Description
1329528	21	06/07/1999	06/17/1999	Modify copper DC bus. Modification includes cutting the bus and drilling slotted holes in the bus. Bus consists of (2) - 1/2 Inch X 6 inch copper busses per polarity (total 4 bars). Cut off length and hole locations will be provided by EME. Bus bars will be provided to shop by EME. This effort is in support the Unit 6 return to service. (TJ Tomes Ext. 46-135)

rand Total: **79 Tasks**

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 35c
PAGE 8 of 8

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB-2)
DOCUMENT NO. 2
PAGE 8 OF 8

EXHIBIT NO. _____

DOCKET NO: 990001-EI

WITNESS: CHARLES R. BLACK

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT: 1) DEPOSITION OF CHARLES R. BLACK TAKEN BY COMMISSION STAFF ON OCTOBER 29, 1999; AND 2) TAMPA ELECTRIC COMPANY'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 21-27).

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 33
COMPANY/ WITNESS: PSC Staff
DATE: _____

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	DOCKET NO. 990001-EI DATED: OCTOBER 19, 1999

DEPOSITION OF: CHARLES R. BLACK

TAKEN BY: The Staff of the Florida Public Service Commission

PLACE: Tampa Electric Company
Teco Plaza
702 North Franklin Street
Tampa, Florida

TIME: Commenced at 9:00 a.m.
Concluded at 11:10 a.m.

DATE: Friday, October 29, 1999

REPORTED BY: Donna W. Everhart
CSR, RPR, CP, CM
Certified Shorthand Reporter
Notary Public
State of Florida at Large

APPEARANCES:

KENNETH R. HART, ESQ., and LEE L. WILLIS, ESQ., Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, Telephone No. (850)224-9115, appearing on behalf of Tampa Electric Company.

WILLIAM COCHRAN KEATING, ESQ., Staff Counsel, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399, Telephone No. (850)413-6199, appearing on behalf of the Florida Public Service Commission.

C. THOMAS DAVIDSON, ESQ., McWhirter, Reeves, Post Office Box 3350, Tampa, Florida 33601, Telephone No. (813)224-0866, appearing on behalf of FIPUG.

ALSO PRESENT:

TODD BOHRMANN, FPSC, Division of Electric & Gas

MARK R. LAUX, Tampa Electric Company

DEIRDRE A. BROWN, Tampa Electric Company

I N D E X

	PAGE NO.
STIPULATION	4
SIGNATURE PAGE	80
CERTIFICATE OF REPORTER	81
ERRATA SHEET	82

WITNESS:

CHARLES R. BLACK

Examination by Mr. Keating	5
Examination by Mr. Davidson	48
Examination by Mr. Keating	76
Examination by Mr. Davidson	78

E X H I B I T S

NUMBER	DESCRIPTION	PAGE
1	Gannon Unit 6, 1999 Major Outage Turbine Work Scope Diagram	59
2	OSHA Report on TECO's Gannon Plant Explosion	75

S T I P U L A T I O N

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.

THEREUPON,

CHARLES R. BLACK

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

EXAMINATION

BY MR. KEATING:

Q. Good morning, Mr. Black.

A. Good morning.

Q. My name is Cochran Keating. I'm with the Public Service Commission. What is your position with Tampa Electric?

A. I'm the vice president of energy supply.

Q. What division of Tampa -- is energy supply a division --

A. Yes, it is.

Q. -- or a department?

A. Yes.

Q. What departments or other subdivisions of the organization fall under that?

A. I basically have responsibility for the operation and maintenance of all of Tampa Electric's power plants as well as the associated engineering support and staff functions associated with the power plant.

Q. Does your division maintain

department-specific tagging procedures to be used during power plant or unit's maintenance outage?

A. Yes, it does.

Q. Does TECO also have -- are there any other sets of tagging procedures used by Tampa Electric? Let me clarify that.

A. Okay.

Q. It doesn't -- not just in areas involving power plant maintenance.

A. Yes. There are other tagging procedures for other areas of the company.

Q. What is the -- what is the purpose of the tagging procedures that you use for power plant maintenance?

A. The purpose is to provide for the safety and well-being of the people working on that equipment, and the procedure is structured to ensure that the equipment is in a safe state before any work is performed.

Q. How does a piece of equipment get tagged?

A. The individual, the authorized individual as defined by our tagging procedures notifies the tagging supervisor, who is typically part of the operating crew, that they wish to have a particular piece of equipment tagged out or made ready for

maintenance.

The tagging supervisor would then perform the functions necessary to ensure the safety of that piece of equipment, and then the person requesting the tagging would be notified. That person would then check the tags to ensure that the equipment being requested has been appropriately tagged, and then the maintenance would begin.

Q. When does a piece of equipment get tagged?

A. Typically equipment is tagged at the request of an authorized individual in the plant or in the case of a major outage, tagging can be prerequested. If we have a major outage and there's a lot of work going on to expedite the process, you can put your tagging request in prior to the outage starting.

Q. Was the maintenance outage at Gannon Unit 6 considered a major outage?

A. Yes, it was.

Q. Was tagging -- what was the term you used -- prerequested?

A. Yes.

Q. How does a piece of equipment physically get tagged?

A. It depends on the particular piece of equipment. The intent is to make that piece of equipment safe. So if it's an electric motor or something coupled to an electric motor, the procedure may be different than if it's a boiler or a piece of electrical switch gear equipment.

So there are procedures to determine how that piece of equipment is to be made safe, but it's kind of specific to the individual pieces of equipment. Basically you check for things that you ensure that it's electrically isolated, that it can't be energized from the electrical side.

If there's steam or high pressure water, high energy sources associated with it, like a pump, then you would verify that all those sources have been isolated as examples of how the equipment is tagged. The operating personnel have that responsibility and are familiar with the operation of the equipment and understand what it means to put the equipment in a safe condition.

Q. When the equipment is tagged, does that indicate that the equipment is safe to work on or does it indicate that it's in an unsafe state?

A. When a piece of equipment is tagged, that means that it has been isolated from energy sources

and it is now safe to work on.

Q. So if the equipment was in a state that was still considered unsafe to work on, it wouldn't be tagged?

A. Tagging a piece of equipment provides the procedural assurances to our crew members that a piece of equipment is safe to be worked on. If a piece of equipment is not tagged, it may or may not be safe to work on, but they don't have the assurance that's provided by the tagging system.

Q. Are there certain limited persons who have the authority to make the decision to tag a piece of equipment?

A. The tagging procedure requires the individuals that request tags to be authorized representatives as defined by our tagging program.

Q. And in the case of the crew working at Gannon 6 on April 8, was the crew supervisor authorized to make a decision --

A. Yes, he was.

Q. -- to request tagging? What training is required of a person who's authorized to request tagging in regard to the tagging procedures?

A. They have to have received training on the tagging procedures as well as other safety and

environmental training.

Q. What does that training consist of?

A. The basic program is an annual program that is a two-day safety and environmental training program conducted within energy supply.

Q. Are those persons given any sort of refresher training during their time with Tampa Electric?

A. Yes.

Q. How often would they receive that sort of training?

A. We shoot for annually. Sometimes it's longer than annually but every two or three years.

Q. There's no requirement that it be done annually?

A. There is a procedure that all persons should receive the safety and environmental training annually, and we attempt to do that, and in large part do do that. We have some scheduling conflicts and things that preclude us from always doing that, but that's the procedure.

Q. Are those people who have the authority to make the decision to tag a piece of equipment, are they tested on any tagging-specific procedures?

A. No, not that I'm aware of.

Q. In your tagging procedures, is there any person -- let me rephrase the question.

Can a person have authority to make the decision to tag a piece of equipment without, I guess, consent of another person?

A. Yes. Yes, they can.

Q. Are there different types of tags used by TECO in its production department?

A. In the energy supply area, we basically have tags that are identified as mechanical systems, electrical systems, and then we have something called a master tag.

Q. And what's the function of each of those types of tags?

A. The differentiation between the electrical and mechanical tags is simply to designate whether the system is electrical or mechanical.

The master tag indicates that there are several tags -- our definition is more than five -- associated with a master tag that when a master tag is hung, it signifies that all the tags that are listed on the master tagging list for that system have, in fact, been placed into -- placed on the equipment.

Q. Where would the master tag be hung typically during a unit maintenance outage?

A. There is a master tag board located outside of the supervisor of plant operation's office. In addition, we have a portable master tag board that we use during major outages that's located in the vicinity of the equipment being maintained.

Q. And during the outage at Gannon Unit 6 in April or beginning of March, was there the portable board placed near the work site?

A. I'm not sure.

Q. Did you use master tagging procedures?

A. Yes, we did.

Q. Within those three categories that you gave me, are there different colors on tags or any other indication on the tag that differentiates it from another type of tag?

A. The tags are marked at the top whether it's an electrical or mechanical tag.

Q. And beyond that, there's --

A. The master tags I think are orange.

Q. So there wouldn't be a mechanical -- of all the mechanical tags, they're all going to look the same?

A. Yes.

Q. And the same with the electrical tags?

A. Uh-huh.

Q. Which people in the plant have been trained regarding tagging procedures?

A. The operating staff, the operating crew is overseeing tagging training as well as the maintenance personnel. And obviously the plant management and engineering staffs are also trained on the tagging process.

Q. Were all of the maintenance personnel who were working on Gannon Unit 6 trained in tagging procedures?

A. I believe they were.

Q. Do you have any reason to believe that any of them weren't?

A. I do not.

Q. How does a person who's properly trained in the tagging procedures confirm his interpretation of a tag on a piece of equipment?

A. For an electrical or a mechanical tag, once someone has requested that a piece of equipment or a system be tagged out, that request is given to the operators, and the tagging supervisor that resides on the operating crew has

the responsibility for determining what actions are necessary to place that piece of equipment in a safe condition, and that tagging supervisor ensures that those actions have been taken prior to placing the tag.

Once the tag has been placed, the tag requester's responsibility is to physically go to the location of the tag and visibly verify that the tag has been hung, and at that point that's his confirmation that the system is safe.

Q. I asked just a minute ago about the members of the crew, the maintenance crew assigned to Gannon Unit 6. You told me that you believe that they had all received training in the tagging procedures. Do you know if they had all received the same level of training?

A. I don't know.

Q. Were some members of that crew more experienced than others?

A. Yes.

Q. Do you know what the experience level ranged from?

A. It seems that I recall the experience ranged from about six and a half years to 21 years.

Q. So what would the maintenance crew's tagging procedure training consist of?

A. It's a training program that's part -- the tag-out lock-out portion of the training is part of our environmental and safety training. And as part of that, there is videotape that's part of the training as well as live instruction on the elements of our tagging process, and that's done in conjunction with the other safety and environmental training that we perform annually.

Q. Do they receive the same training that a person who is authorized to make the decision to tag a piece of equipment would receive?

A. Yes.

Q. Would the maintenance crew be tested on tagging-specific procedures?

A. They attend the training. I'm not aware if there's any specific test associated with that.

Q. Are tagging procedures used industry-wide as a safety mechanism during maintenance outages?

A. Yes.

Q. You mentioned that TECO had tagging procedures in other areas. Could you elaborate on that, just briefly explain what other circumstances tagging procedures might be used in?

A. In the energy delivery part of the business, the transmission distribution side of the business, they also have requirements for ensuring that the equipment is safe before they work on it, and they have their own set of tagging procedures that I'm not very familiar with, but I know that they exist.

Q. Have TECO's tagging procedures -- and this is limited to those procedures used in the unit maintenance or in your department -- have those procedures evolved through time?

A. Yes.

Q. Have tagging procedures industry-wide evolved through time, to the best of your knowledge?

A. In a general sense, I would say they have.

Q. When were TECO's tagging procedures first developed?

A. I don't know.

Q. Have TECO's tagging procedures been modified since they were first developed?

A. I believe they have.

Q. Have they been modified during your time with TECO?

A. Yes.
Q. Do you know when they were last modified?
A. I don't know.
Q. What's the procedure that TECO uses to modify its tagging procedures?
A. Well, speaking again for energy supply. I'm not familiar with what the other parts of the company do.
Q. And that's the only intent of my question.
A. Within energy supply, we work with the corporate safety department and we have internal to our department we have a safety coordinator, and there's also a corporate safety department, and we would assemble a team of employees to work with the energy supply safety coordinator to develop changes that we think are appropriate to make our system better or that we believe are necessary to comply with new rules and regulations, and those activities would be coordinated and reviewed by our corporate safety staff.
Q. Are those done on a periodic basis, a set periodic basis, say annually by anyone?
A. Not that I'm aware of.
Q. So modifications to the tagging

procedures would be initiated by -- to clarify again, the production department's tagging procedures would be initiated by the production department's safety group?

A. They could either be initiated by individuals within energy supply or it could be initiated by our corporate safety people making us aware that a federal regulation or rule had changed that required us to modify our tagging procedures. So it could have occurred from a couple directions.

Q. Under TECO's current tagging procedures, at what point during a planned maintenance outage of a unit should the generator and its parts be tagged?

A. It depends on the nature of the work being performed. In the particular case of Gannon 6, the work being performed was a major overhaul of the turbine and the generator. Since we knew that work was going to be accomplished as part of the outage, there was a pre-outage pre-tagging request put in to identify the fact that when the appropriate testing had been completed, that it was desired by the maintenance crew to have that system tagged.

Q. Were any parts of the generator at Gannon Unit 6 tagged when the maintenance crew began disassembling the generator on April 8?

A. No, it was not.

Q. And could you tell me again why?

A. The supervisor in charge of the work, my understanding is that he was aware that electrical testing was continuing on the generator and that because of that, had not requested the generator to be tagged.

Q. If a person fails to properly tag a piece of equipment, does Tampa Electric sanction that person in any way?

A. If someone violates our tagging procedures, that is a condition that we deal with through our discipline program up to and including termination depending on the severity of the accident or the infraction.

Q. Has that happened in the past?

A. Yes, it has.

Q. Does TECO keep any records on that?

A. I don't know.

Q. To the best of your knowledge, during your time at TECO, how many times has that happened?

A. I can't quantify it, but during the time that I've been responsible for the energy supply department, I'm aware of several times that people have been disciplined for safety-related actions. I can't give you a number, but --

Q. How long have you been with that department?

A. It will be three years next month.

Q. To the best of your knowledge, what types of discipline were taken or would be taken?

A. Within our discipline system, we have various stages of discipline, the lower piece being something we call an oral reminder, proceeds up through several steps. The most significant step is called a decision-making leave where the employee basically is put on notice that he must comply with the company's rules and regulations or if any problems occur within a one-year period, he will be terminated.

Of course, the ultimate step in the discipline process is termination. And depending on the nature of the safety violation, it would fit into one of those disciplinary categories, and it's handled on a case-by-case basis consistent with our normal discipline process.

Q. I had originally asked about the circumstances where a person fails to properly tag a piece of equipment, and when you said that -- when I asked how many times it happened in the past to your knowledge, you told me that several times came to mind. I just wanted to clarify your answer. When you said that this happened several times, is that for the limited circumstance of improperly tagging a piece of equipment, or would that include any violation of the tagging procedures?

A. No, that -- I appreciate the clarification there. My comment was with respect to all safety-related actions. Specific violations for tagging violations, I'm not aware of any in my tenure.

Q. Are you familiar with an organization or a program at TECO called the safety and environmental awareness or action leaders?

A. Yes.

Q. Could you explain to me what that group or program does?

A. Each maintenance crew, particularly at Gannon, which has this program in place, each maintenance crew has what's called a safety crew

leader. And that safety crew leader represents that maintenance crew on the SEAL committee, the safety and environmental action leaders. That group meets periodically at least monthly to discuss safety issues of a general nature or of a specific nature relative to things going on in the plant in an effort to create a more safe work environment.

Q. So this group is comprised of safety crew leaders from each crew at Gannon?

A. Yes. As well as the management of Gannon is represented, and I believe there's also engineering representation.

Q. How are the members of that group selected to participate?

A. I believe that people become safety crew leaders by volunteering.

Q. And the other persons participating in the group, is that part of their job description?

A. Are selected by management as part of their job, yes.

Q. I think you might have answered this already, but how often does the SEAL group meet?

A. They meet at least monthly.

Q. What is the format of a typical meeting?

A. The meetings typically are an hour. Sometimes they're more than that. And as I said, at times the issues are general kind of safety issues, review of recent injuries, review of accidents, what needs to be done to address specific items. Other times it's more general topics, safety topics, so they vary.

Q. Is it set up as an open discussion forum?

A. There are typically agendaed items that are to be discussed, but it's a very interactive discussion group.

Q. When was that group formed at TECO?

A. I don't know.

Q. Do you know when it was -- when it was formed at the Gannon plant?

A. It's been -- it's been at Gannon for the whole time that I've had responsibility for the department. I don't know how far back beyond that.

Q. Again, this is ground I may have covered already, so please pardon me, but does TECO periodically review its tagging procedures?

A. Yes.

Q. And how often does it perform a review?

A. It's not on a scheduled basis. It's on

more an as-needed basis.

Q. And who is involved with reviewing the tagging procedures?

A. Typically any changes to the tagging procedures are accomplished through a group comprised of employees from all of the energy supply locations as well as the energy supply safety coordinator working in conjunction with our corporate safety staff.

Q. When did TECO most recently review its tagging procedures?

A. I'm not sure when the last time the energy supply procedures were reviewed.

Q. When was the last time that any revisions were made to the tagging procedures?

A. I don't know exactly when it was.

Q. How are personnel informed of or taught new procedures after a revision occurs?

A. When a revision occurs, there is a general training activity within each location to make all the employees aware of the change to the process. This is done through the supervisors as well as larger group meetings at the facilities. In addition, the changes are incorporated into the environmental and safety training that we perform

on an annual basis and becomes the new basis for that training.

Q. Could you describe the training that's necessary to properly assess whether a piece of equipment should be tagged?

A. The determination of whether a piece of equipment should be tagged is really something that's developed through on-the-job training and experience in working in your classification.

The basic rule is there's very few pieces of equipment that should be worked on without being tagged. So the general rule is if you're going to be working on something, it should be tagged, and anything else would be an exception to that.

Q. Who provides the tagging training for the maintenance crews?

A. The safety and environmental training is accomplished at our skills training center, which is our centralized training facility for energy supply. And it's provided by the training supervisor that we have at the skills training center responsible for doing it.

Q. So TECO provides the training?

A. Yes.

Q. Does the Electrical Workers Union provide

any training?

A. I'm not aware of any TECO-specific training that the IBEW provides. There may be other generic types of training that's provided to them, but I'm not aware of it.

Q. Are you aware of any other groups that would provide that sort of training, any other industry groups?

A. We have from time to time not specifically associated with tagging procedures but with respect to other safety items, we do have people from the outside come in. We get regular visits from the fire department at each of the locations, and they come in and inspect the facilities and work together on emergency response plans and that sort of thing.

So we do have outside involvement there, but there's no outside involvement specifically on the tagging training.

Q. What training materials exist regarding tagging procedures?

A. There's the training material that's part of the curriculum for our safety and environmental training as well as very specific procedures identified in our safe work practices manual, a

copy of which is issued to each employee.

Q. And each employee gets to keep that manual --

A. Yes.

Q. -- for themselves?

A. Yes.

Q. Are there any other materials that are provided to employees to keep?

A. Not that I know of.

Q. Do all of the employees in the production department receive that safe work practice manual?

A. Yes, they do.

Q. And all of the maintenance crew?

A. Yes.

Q. I think you used the term "tagging supervisor" at one point. What is a tagging supervisor?

A. Tagging supervisor is someone that's designated on the operations crew that is knowledgeable in all the systems in the plant and can verify what steps are necessary to be taken to ensure that a piece of equipment is completely tagged down and is safe. The actual tagging process is completed by the operating crew under the direction of the tagging supervisor.

Q. I want to make sure I understand the organization level. You've got the maintenance crew at the bottom, the crew supervisor, and then a tagging supervisor above him?

A. Within the maintenance organization, you have the crew, and they report to the supervisor. On the operations side, which is a separate organization, you have operators. There is one classification of operator which we call the watch engineer classification that we have designated as the tagging supervisor.

Q. And what is a tagging operator?

A. I'm not sure I understand that term.

Q. That's not a position or a job that you know of?

A. Tagging operator? No, it's not.

Q. On page 4 of your testimony you stated that the company's safe work practices require the supervisor of the crew to conduct a job briefing with the crew before the start of each job; is that correct?

A. Yes. That's correct.

Q. How is a job defined?

A. A job really in that context is defined as the activities that the crew is expected to work

on during that shift of their work, as opposed to a specific piece of equipment or something that you could characterize as a job. There may be many different jobs that the crew is working on, but it's the supervisor's responsibility to provide the information in our procedures relative to the job briefing for all of those jobs.

Q. So the safe work practices, the TECO safe work practices require the supervisor of the crew to brief the crew before each shift?

A. That's correct.

Q. Okay. Did the supervisor of the maintenance crew working on Gannon Unit 6 on the morning of April 8 meet with his crew before they started work that morning?

A. Yes, he did.

Q. What was the crew supervisor's role during the planned maintenance outage at Gannon Unit 6?

A. Which supervisor?

Q. I'm sorry. The maintenance crew supervisor.

A. Of the crew that was performing the work on the --

Q. Yes.

A. -- turbine generator?

Q. Yes.

A. His role was to basically be the responsible person in charge for that work and all the duties and responsibilities that are associated with that. His role was also to provide technical assistance to any of the crew members performing the work if they needed some help or some advice.

Q. What tasks was that particular crew, the maintenance crew working on Gannon Unit 6 the morning of April 8, what tasks were they supposed to perform at Gannon Unit 6 that day and beyond?

A. The general scope of work was to perform a major turbine overhaul on the high pressure part of the turbine as well as a complete generator inspection. And the work for that particular day, the disassembly of the high pressure turbine, had begun, and there were continuing work items associated with that, and the work on the generator had not yet begun.

Q. Prior to April 8, had any members of that maintenance crew been working at Gannon during the maintenance outage that started in March?

A. Yes.

Q. Had all of the members of that

maintenance crew been working at Gannon Unit 6 before that morning?

A. No.

Q. How many members of the crew were new to Gannon Unit 6 that morning?

A. I think there were four individuals that were new.

Q. And how many total crew members were there?

A. I don't remember exactly.

Q. Could you give me just a rough estimate about the size of the crew? I'm just trying to get a feel for --

A. 10 to 12 or 13, something like that.

Q. Had the supervisor of the maintenance crew working on Gannon Unit 6 the morning of April 8 been working at Gannon Unit 6 for that particular maintenance job prior to April 8?

A. I believe he was.

Q. He wasn't --

A. He had not been there for the entire outage.

Q. He didn't come over with the four new crew members on the morning of April 8?

A. No.

Q. According to TECO's original schedule for all the maintenance activities during that outage at Gannon Unit 6, when was the generator scheduled to be purged of all the hydrogen?

A. I think the original schedule, the best of my recollection, had it around the 5th of April.

Q. And it hadn't been purged at that time?

A. That's correct.

Q. Why hadn't it been purged at that time?

A. The electrical personnel at the plant were performing a test on the generator called a megger test, and they had not gotten a good test result and were continuing to do testing work on the generator.

Q. What is a megger?

A. A megger test applies a voltage to the generator and basically is a measure of the condition of the generator's insulation. And if you get what's called a low megger, it basically measures the resistance of the generator insulation. If that number is low, it can indicate that there's either moisture present causing the resistance to be low or that there's a physical problem with the insulation in part of the

generator.

Q. Is the generator typically not released for maintenance before a good megger test is achieved?

A. The normal procedure is to megger the unit until you have a good understanding of the condition that you're dealing with. If it's a physical problem, that causes one course of action. If it's determined that it's a moisture-related problem, maintenance may begin at that time once we've made that determination. We would still not have had a good megger, but we would have made the determination as to the condition.

Q. Was the maintenance crew supervisor -- and, again, that's the crew that was working on Gannon 6 the morning of April 8 -- was he aware that a good megger had not been achieved yet?

A. I believe he was.

Q. And again, I understand it's to the best of your knowledge.

A. Right.

Q. How would he have been informed?

A. Informed of?

Q. Of the fact that a good megger had not been achieved?

A. I think his information was based on the fact he knew the meggering testing was occurring, and he was also aware that the electric personnel were continuing to do testing even the morning of April the 8th.

Q. Was there -- is there any procedure in place by which he would have been informed, or would he just get this information through communicating with the personnel at the plant?

A. It would basically be through communication with the personnel at the plant.

Q. Who else of the people that were involved in the maintenance outage at Gannon Unit 6, who else would have known of this condition on the morning of April 8, and that is, that the unit had not gotten a good megger test yet?

A. Certainly people in the electric area of the plant that was performing the test would have been aware of it. The operating crew would also have been aware of it.

Q. Was the maintenance crew that was working on Gannon Unit 6 that morning aware of the original maintenance schedule?

A. I don't know that for a fact. They may or may not have.

Q. And again, I should preface that to the best of your knowledge. Typically would the crew have had access to that schedule?

A. Yes.

Q. Was the supervisor, to the best of your knowledge, aware of the schedule?

A. Yes.

Q. And how would he have been -- strike that.

Was it the supervisor's responsibility to keep up with that schedule, not necessarily to follow it to the letter but to --

A. Yes. He should have been aware.

Q. -- to follow along with it?

A. Yes.

Q. What other individuals above the supervisor should have been aware of the schedule?

A. There is a maintenance superintendent at each one of the plants, and that person should have been aware as well as the plant managers involved with the major outage.

Q. What state of disassembly was Gannon Unit 6 in on the morning of April 8 when the maintenance crew arrived to work on it?

A. With respect to the turbine generator job

the crew was working on, the front standard of the machine had been opened. The casing of the high pressure turbine had been removed. The main steam valves had been removed. The cross-over piping connecting the high pressure to the low pressure turbine had been taken off. The inspection ports on the low pressure turbine had been opened. And various and assorted support piping, seal oil piping, turning gear, things were in various states of disassembly.

Q. Had this disassembly proceeded as originally scheduled?

A. Generally as originally scheduled. There were some differences from the original schedule, but in general it was proceeding as planned.

Q. Typically would the hydrogen in the generator have already been purged from the generator when the unit has reached that state of disassembly during a maintenance outage?

A. What we typically see is that it would, based on the normal times associated with the testing that's required before the hydrogen is purged. So typically at that state of disassembly, yes, the hydrogen would be out of the machine, but that's not a hard and fast requirement. It's

depending on the circumstances of the testing.

Q. Can you think of any occasion in your experience with TECO when a unit was disassembled to the extent that Gannon Unit 6 was disassembled the morning of April 8 but not yet purged of the hydrogen?

A. I'm not aware of any, but I wouldn't necessarily be as closely involved with the actual maintenance activities to know that.

Q. What is your involvement in a maintenance, during maintenance activities?

A. My involvement starts with the overall maintenance planning for the year, where the outages are going to occur, the length of the outages, what work will be accomplished during those outages, what sort of financial resources are going to be applied, that sort of thing.

Once the outages are planned and they actually begin, I get periodic updates on the status of the outage, any problems that are occurring, particularly as they might affect the schedule of the outage or the budget.

Q. What is the doghouse on the unit?

A. Doghouse is a term that's used to identify the structure. It's a small building-like

structure that encloses the collector rings on the outboard end of the generator. Those collector rings are the interface between the generator and the exciter, and the structure that encloses that generator, a collector ring area, is called the doghouse.

Q. Is it safe to remove the doghouse from the unit before the generator has been purged of hydrogen?

A. Yes, it is.

Q. Had the doghouse been removed from Gannon Unit 6 by the morning of April 8?

A. Yes.

Q. Typically would hydrogen have been purged from the unit prior to the doghouse being removed, and that is during a typical maintenance outage?

A. Depending on the other work going on, it could go either way. It could be purged prior to removal of the doghouse or the doghouse could go first. It just depends on the work.

Q. On the original -- on the original maintenance schedule, was the doghouse scheduled to be removed prior to hydrogen being purged from the unit?

A. I'm not aware that the original schedule

defined the work down to the level of detail that removal of the doghouse would have been a specific item identified on the schedule. And so I don't know what the original plan was.

Q. How long had the maintenance crew at Gannon Unit 6 the morning of April 8 worked under the supervision of that particular crew supervisor?

A. That's a different answer for each member of the crew. The crew that was performing that work has a designation that we call an ES designation, which basically means that they can be assigned to any energy supply location.

For major overhaul work like we were doing on Gannon 6, we will look for our most experienced and technically best people from all of our locations, and we will assemble them into a crew, an ES crew, and also look for supervisors that have the technical skills that we need and assign those to the crew.

So the people working on that outage had worked under the supervisor in various other assignments through the years, but for this particular outage the crew was assembled specifically for the work that we were doing, and that included the selection of the supervisor.

Prior to I believe it was 1996, we had a group called a traveling maintenance crew. It was later called generation and engineering maintenance. And as part of that structure, there was a specific crew of people that were turbine generator maintenance mechanics, and their function was to do major overhaul work. That crew had a supervisor.

The supervisor that was supervising the work on April 8 was one of the supervisors that came from that turbine generator maintenance traveling and maintenance crew. In addition, several of the mechanics that were working on the job also came from that traveling maintenance crew where they worked with the supervisor, but not all of the people working on the crew came from the traveling maintenance crew.

Q. So the maintenance crews at TECO or the maintenance personnel travel around to work on various units at various plants?

A. Normally each mechanic is assigned to a crew at a location and they work there. And only in the cases of major maintenance outage work where we need very specialized turbine generator or specialized boiler work do we move those people

around, but in those major outages crews are assembled based on the technical requirements we have.

Q. What types of -- what types of mechanics comprised the crew that was working on Gannon Unit 6 the morning of April 8?

A. The classifications were basically all maintenance mechanics except for one individual who was a production apprentice. The maintenance mechanics that were selected for that job were very experienced in doing work of that type, which was why they were selected to form that crew and do the work.

Q. Had the production apprentice in the group worked under the supervision of that particular crew supervisor in the past?

A. I don't know.

Q. To the best of your knowledge, did the supervisor tell his crew at the morning briefing on April 8 at Gannon Unit 6 that the hydrogen had not been purged from the generator?

A. Could you say that again? Make sure I get everything right.

Q. To the best of your knowledge, did the supervisor tell the maintenance crew at Gannon Unit

6 on the morning of April 8 during his morning briefing that the hydrogen had not been purged from the generator?

A. To the best of my knowledge, he did not say that.

Q. To the best of your knowledge, did he tell his crew that morning that electricians were still conducting meggering tests?

A. I believe that he did.

Q. That he did tell them that electricians were still conducting meggering tests?

A. That the electrical activity was still going on.

Q. To the best of your knowledge, did the supervisor tell the crew at Gannon Unit 6 on the morning of April 8 in his morning briefing that the original maintenance schedule had been -- had been deviated from?

A. I'm not aware that he discussed that with them.

Q. On what do you base your knowledge of what the supervisor told his crew at the morning briefing?

A. My knowledge is based on a review of the interview conducted with the supervisor by OSHA and

also on feedback that I've received from our risk management personnel, who also interviewed the supervisor as well as some of the other employees.

Q. To the best of your knowledge, did the crew believe after the morning briefing that it was safe to open the generator?

A. Based on the information that has been made available to me, my belief is that they did feel it was safe.

Q. And to the best of your knowledge, do you believe that the entire crew had that belief?

A. Yes, I do.

Q. And, again, on what do you base that knowledge?

A. Again, primarily on feedback from interviews conducted by our risk management personnel and feedback from interviews that the OSHA people also conducted.

Q. To the best of your knowledge, did the crew believe that they were to begin disassembly of the generator?

A. Yes.

Q. Is there any reason you can think of how the crew could have known or expected that the hydrogen had not been purged from the unit?

A. Would you repeat that for me?

Q. Sure. Is there any reason that you can think of to explain how the crew could have known or expected that hydrogen had not been purged?

A. The responsible person in charge of that activity, which in this case was the supervisor, had the responsibility of communicating the hazards associated with the work that he was asking the employees to go and perform.

Based on the communication that the supervisor had, the general feeling of the maintenance crew was that communication created a sense that the generator was safe to work on. Other than that communication, I'm not aware of anything that would have led the maintenance employees to believe that the hydrogen had been removed from the generator.

Q. Did the four crew members who were new to the crew that morning on April 8 at Gannon Unit 6, to the best of your knowledge, did they have the same information available to them that the crew members who had been there previously had known?

A. They were all in the same job briefing discussion, so the information conveyed by the supervisor on the morning of April the 8th was the

same for those folks as the other individuals. Any knowledge that they may have gained by virtue of working at Gannon on the outage prior to that time, I can't speak to that. I don't know.

Q. I've got a couple questions here to get off the topic of Gannon for a minute and go towards the Polk unit.

MR. DAVIDSON: Before we do that, could we have a brief recess?

MR. HART: Certainly.

(Brief recess.)

THE DEPONENT: Before we proceed, one of the questions that you asked me earlier, I'd like to provide a little clarification, if I could. You had asked a question of would the crew working on the generator have been aware of the electrical testing that was being performed.

And in addition to the answer that I provided previously, I wanted to clarify that minutes prior to the explosion, there was an announcement made over the public address system that to stand clear of the Unit 6 generator, that we're beginning to megger test the unit. So that would have been another way that the maintenance crew would have known that electrical testing was

proceeding.

BY MR. KEATING:

Q. And what is your knowledge of that announcement based on?

A. Again, feedback from the interviews that were conducted with the employees.

Q. I lied. I do have one more question or a couple more questions about Gannon.

A. Okay.

Q. I believe in your testimony that you stated that the maintenance crew member who removed the access cover to the generator, and in turn resulting in release of the hydrogen and the explosion, was the sole production apprentice on the crew?

A. We believe that's the case.

Q. To the best of your knowledge, were any of the other members of that maintenance crew that morning planning to remove any other access cover on the generator?

A. The feedback that I've gotten, again from the interviews that were conducted, is that at least one of the other maintenance mechanics indicated that he was assembling tools to begin disassembly of that access cover on the opposite

end of the generator.

Feedback from one of the other mechanics indicated that he was performing another job at the time of the explosion but had he not been doing the other job, he would have been assisting the production apprentice in the removal of the hatch cover that was removed.

Q. And now I'll get back to the Polk unit.

A. Okay.

Q. Or Polk unit. I'm not sure how it's said in these parts. When did Tampa Electric decide to accelerate the in-service date of the Polk Unit 2 from January 2001 to October 2000?

A. I'm not sure.

Q. Did you have any role in the decision to accelerate that in-service date?

A. My role in the project is to be responsible for the engineering and the construction and the placing in-service. In coordination with other people within Tampa Electric, the decision on when it should be placed in-service was made. I did not make that decision.

Q. What incremental costs did Tampa Electric incur to put Polk Unit 2 in service by October

2000?

A. I don't know.

MR. KEATING: That's all the questions I have.

EXAMINATION

BY MR. DAVIDSON:

Q. Mr. Black, I'm Tom Davidson. I represent the Florida Industrial Power Users Group. I believe we met yesterday --

A. Yes, sir.

Q. -- when you took us on a site visit.

When your tagging procedure takes place, can you tell me -- I'm a little confused as to whether that was done in this case on the morning of the explosion, whether the tagging was the responsibility of the maintenance supervisor or the operating person.

A. In this particular case, as part of planning for the outage, since we understood the work that was to be performed on the turbine generator and we knew that that system had to be tagged in order to perform that work, there was a tagging request submitted prior to the outage as part of the outage planning to let the operating crew know that that was one of the things that had

to occur. That's the only request that was made.

Q. Who made that request?

A. That was made by the planner, whose responsibility it was to plan the maintenance events associated with that outage. Part of his responsibility is to submit any pre-outage tagging request, which was a notice to the operating crew that when it was appropriate, we need this piece of equipment tagged out so we can do our maintenance. No other requests that I'm aware of had been made to have the system tagged.

Q. Now, the operating people or the operating crews are the people who actually run the machinery during the normal course of producing electricity there at the plant; is that correct?

A. Their responsibilities are typically the operation of the equipment and the systems.

Q. And they're full-time there on the plant at all times, I take it?

A. That's correct.

Q. And the maintenance crew in the case of a major outage comes in to do the work and do the maintenance on the equipment that's going to be worked on; is that right?

A. That's correct.

Q. And they are two separate organizations or crews; is that right?

A. That's right.

Q. Now, prior to work commencing on the generator -- let me back up.

As to work on the generator, which tag would have been the appropriate tag for generator work? You mentioned a master tag and then some other tags?

A. It would have been the master tag for the generator system.

Q. Is there such a thing as an electrical tag?

A. There is.

Q. Would there not have been an electrical tag that should have been assigned to the generator work?

A. With the master tag, as part of the master tagging process, for every master tag there is a list of specific equipment tags, some of which are electrical, some of which are mechanical, that have to be executed before the master tag can be posted signifying that the entire system had been tagged out.

Q. Prior to work commencing on the generator

on Unit 6, maintenance work commencing, whose responsibility was it to determine if the generator had been tagged out?

A. The responsibility for assuring that the tagging had been done and it was safe to perform the maintenance was the responsibility of the supervisor.

Q. Of the maintenance supervisor?

A. That's correct.

Q. And if I understand your testimony correctly, the generator was not tagged out?

A. That's correct.

Q. And that means that no one had put a tag on the generator saying it was safe to commence work on that?

A. That's correct.

Q. What responsibility did the crew people have to determine if the generator was tagged out?

A. Under our tagging procedures, each employee, including each maintenance mechanic, has the ability to have his name added to the tag if he so chooses. If he chooses to add his name to the tag, then he takes on responsibilities equal to that of the supervisor for assuring that the system has indeed been tagged out and that it's safe to

work on.

That's not a requirement. The system is structured so that the responsibility for ensuring that the appropriate equipment has been tagged and equipment is safe is the responsibility of the supervisor. The employees, though, also have an obligation to ensure their own safety and as part of that, can choose to have their name added to the tag, but that is their choice.

Q. Are you familiar with an organization called OSHA?

A. Yes, sir.

Q. That's an acronym; is that correct?

A. Yes.

Q. What does it stand for?

A. I believe it stands for the Occupational Safety and Health Administration.

Q. And is TECO subject to the regulation of that administration?

A. Yes.

Q. Is TECO required by the regulations of that administration to comply with the OSHA-prescribed tagging procedures?

A. Yes.

Q. Was TECO in compliance with the tagging

procedures prescribed by OSHA on the morning of April 8?

A. We believe we were, yes.

Q. OSHA believed otherwise; is that correct?

A. I'm not sure I'd characterize that as correct.

Q. They cited you, didn't they, for being out of compliance with the tagging procedure?

A. They cited us for not utilizing what they term as group tagging, that's correct.

Q. Now, TECO was assessed a fine by OSHA for not following those procedures?

A. That's correct.

Q. And TECO paid the fine that was assessed for that; is that correct?

A. Yes.

Q. In your position with TECO, are you the one who is responsible for investigating the accidents such as occurred on April 8?

A. The actual responsibility for the investigation was taken on by our risk management department. My responsibility was to provide operational support for what they're doing.

Q. What is the risk management department?

A. It's the division of our company that

manages all of our risk management issues, insurance, those kind of things.

Q. Is there anyone at TECO -- withdraw that.

Was anyone at TECO assigned to determine what, if anything, went wrong that morning for purposes of correcting procedures or to do things to determine how to keep this from happening again?

A. The risk management folks conducted an investigation as well as the OSHA, local OSHA office conducted an investigation. Our corporate safety people were involved with both of those. The risk management folks were involved with the internal activities. The objective of both of those was to determine the cause and then make recommendations towards what was necessary to make it better.

Q. In your position, is it part of your function and duties to learn about what happened in the case of an accident of this type in order to avoid it from happening again, if possible?

A. Yes.

Q. And it would be of interest to you for that at least for that reason?

A. Yes.

Q. The first thing that happened the

morning of 8th was the briefing; is that right?

A. The crew when they reported to work reported to the maintenance shop and met with the supervisor, and that's where the briefing occurred.

Q. Four of those persons had not worked on Unit 6 prior to the accident; is that correct?

A. I believe that's right.

Q. Now, what did the supervisor say at the briefing regarding whether the unit was safe or not safe to work on?

A. He did not, to my knowledge, specifically use terms like "safe or not safe to work on." It was discussed the status of the equipment, the work that was to be done that day, and he made assignments of work tasks to those -- to the individuals, which they left the briefing and went out to execute.

The work assignments were made in terms that were less specific than was necessary to convey the status of the hazards of the job to all the employees.

Q. What was the supervisor's name?

MR. WILLIS: At this point, let's go off the record just a moment.

(Discussion held off the record.)

MR. DAVIDSON: We're back on the record, Mr. Black, and it's my understanding that at this time TECO does not wish to disclose the name of the supervisor for a variety of reasons. And I am willing to enter into a stipulation on the record with your company at this time that I will not seek the name at this time in this deposition and that the company will provide it to us at a later time under a confidentiality agreement which we'll work out.

MR. WILLIS: That's fine.

THE DEPONENT: That will be fine.

BY MR. DAVIDSON:

Q. Now, the statements that you referred to earlier that form the basis of your understanding of what happened in the meeting, are these written statements?

A. The statements of the supervisor that I'm aware of are based on interviews that the supervisor had with OSHA, and those interviews are written.

Q. And they were made available to TECO?

A. Yes.

Q. What was it that you understood that the supervisor said regarding work assignments when he

gave the work assignments to the men? What assignments did he give?

A. The supervisor's statement is that he informed the crew working on the turbine, which was already disassembled and had several work items in process, he assigned them work areas consistent with what they had been doing.

For the generator work, the supervisor stated that he instructed them what he intended for them to do was to get their tools together, to stage the tools, to begin assembly of some of the nonrelated piping not associated with the generator proper, and that that was what he intended for them to do.

Q. Do you recall what the words were that he said? Did he relate what he actually said in the briefing?

A. I don't recall the exact words. To my knowledge, there's not a verbatim transcript of what was said in that meeting. We have what the supervisor instructed them to do, and then we have what the maintenance mechanics heard the maintenance supervisor instruct them to do, but I do not know what the specific words that were used.

Q. What was your understanding as to what

the crew members heard or understood that they were to do?

A. The feedback that I've received is that the crew members believed, based on what the supervisor communicated to them, that not only could they get their tools and stage them to the areas but that the generator was ready for maintenance and that they could proceed with their work.

Q. Now, is the supervisor -- excuse me, was the supervisor on April 8 a full-time Tampa Electric Company employee?

A. Yes.

Q. He was not a contract worker?

A. He was not.

Q. Were the crew members full-time Tampa Electric Company employees?

A. Yes.

Q. They were not subcontractors or contract workers?

A. No, they were not.

Q. The crew members and the supervisors were all on a regular salary with TECO?

A. The supervisor was on a monthly salary. The maintenance mechanics and the individuals

covered under the collective bargaining agreement were paid on an hourly basis.

Q. Now, it was the supervisor to whom TECO delegated the responsibility of assuring the safety of the crew members as far as a safe workplace and ensuring that the generator was purged of hydrogen if it was necessary for it to be purged of hydrogen; is that correct?

A. It was the supervisor's responsibility to assure that the work that was being performed, it was safe to do it, which included the hydrogen and anything else that was required to make it safe.

Q. And under TECO's normal procedures for performing work and assuring safety, it was the supervisor who was the last person in the chain of command who had that responsibility; is that right?

A. That's correct.

Q. The responsibility was delegated to him?

A. Yes.

Q. Now, yesterday you gave us a sketch, and I only got one copy, and I wrote a couple little notes on this one. I'd like to make this an exhibit to the deposition. Call this Exhibit 1.

Using Exhibit 1, would you -- I don't know if you have a pen there. Let me give you -- I

might have a red pen. I do. Give you my red pen. Would you first describe for us what your understanding is as to how the hydrogen escaped from the generator unit?

A. Our understanding is that the hydrogen escaped when an access cover located on the west side of the outboard end of the generator was removed prior to purging the hydrogen from the machine.

Q. Could you mark the location of that cover?

A. (Complies.)

Q. Now, there were three others of those covers on the unit as well, were there not?

A. Yes.

Q. Could you mark where each of those other covers were?

A. This is a side view.

Q. Yes, sir.

A. So there's one on each end, and then there's another one on the other side.

Q. Opposite side of it?

A. So I can only mark two on this view.

Q. Okay. Now, as to the one where the cover was removed on the morning of April 8, would you

just mark that with an X across your circle so we can distinguish it from the other.

A. (Complies.)

Q. Thank you. Now, as part of your duties, I take it you were interested in learning what happened out there that morning?

A. Yes.

Q. And one of the things you learned was that the cover -- well, let me back up. How did you determine that the cover had been removed at the location you've marked on the Exhibit 1?

A. The physical evidence that was reviewed after the explosion indicated that that was the source of the hydrogen. As we discussed yesterday, there are 24 bolts that hold that plate in place, and 23 of those bolts were found in the general area of that plate's place on the generator in a fashion that would lead us to believe that someone took those bolts off and laid them down there.

Q. There is a little ledge of some kind there beside as part of the generator, wasn't there?

A. Yes.

Q. And that's where you found the bolts?

A. Yes.

Q. How big were those bolts?
A. I don't know.
Q. Did you see them?
A. Yes.
Q. Can you give us an estimate, 6 inches, 3 inches?
A. I would guess they're probably 4 or 5 inches long.
Q. And they are threaded, I take it?
A. Yes.
Q. Did you examine or learn of anyone examining the condition of the threading in the bolt holes?
A. I'm not aware of that.
Q. Did you actually view the site after the explosion yourself?
A. Yes.
Q. Did you make a determination as to how or the direction of the blast?
A. The blast seemed to be in the direction directly in line with that access plate that I've marked on the exhibit. That would be to the north.
Q. And it actually blew out the north wall --
A. Yes.

Q. -- and part of the east wall?

A. Yes.

Q. I wrote on there "blast" and I drew an arrow. Is that an accurate representation, or would you like to change that?

A. That was the bulk of the energy seemed to be directed in that direction. There was some damage to the east side of the plant as well, so it wasn't all in the north direction, but there was some directed towards the east.

Q. The staff of the arrow probably should be up where your red mark is, I take it?

A. Yes.

Q. And I wrote in there "access cover." I take it that's in the wrong place; right?

A. Yes.

Q. Why don't you mark that through with your red pen there.

A. (Complies.)

Q. Now, the exciters are over on the east side of the generator; is that correct?

A. Yes.

Q. Have I written that in in the correct place?

A. It's approximately right.

briefing the morning of April 8?

A. Not that I'm aware of.

Q. Have you ever supervised or actually performed any of the kind of maintenance that was being performed that morning yourself?

A. No, I have not.

Q. Do you know whether the supervisor briefed the crew members on the morning of April 8 as to whether -- as to what maintenance had already been done on the turbines and the generator?

A. I'm not aware that there was a discussion of previous work that occurred.

Q. With four new crew members, do you think it would have been prudent for the supervisor to have briefed the new members as to what had already been done?

A. Not necessarily. Given the fact that the supervisor was in charge of the overall operation and through his direction of work activities, I don't know that that was necessary.

Q. What would an experienced maintenance crew member, with the experience level of the people that you had on the job that morning, have deduced from the fact that the doghouse was off of the generator unit as to whether the unit was safe

to operate, safe to do maintenance on?

A. The deduction on the part of the maintenance crew of whether or not the unit was safe should always be based on the fact that the system was appropriately tagged out of service and the tagging procedure identified it as safe. The state of disassembly of the other pieces of equipment associated with the generator could lead someone to believe that the maintenance activities were further along than the actual state may have been.

Q. You had mentioned in your earlier testimony this morning that one of the people involved with maintenance that morning said that if he had not been involved in some other project there, he would have been assisting the worker remove the cover?

A. Yes.

Q. Who was that? Was that the supervisor you were talking about or another person?

A. No. It was the journeyman that was at this position on your diagram (indicating).

Q. Then was it your understanding that that journeyman who would have been assisting was under the understanding that the generator had been

purged also?

A. My understanding is that he believed it was safe to work on.

Q. Does TECO have copies of the OSHA interviews that were conducted?

A. I know of -- I've seen copies of the interview conducted with the supervisor and with the planner. There may be others available, but I'm not aware of them.

MR. DAVIDSON: Are those available to us? I don't know if we can -- which one of these lawyers do I ask that question?

MR. WILLIS: Let me inquire at a break.

MR. DAVIDSON: Okay.

BY MR. DAVIDSON:

Q. I take it the next step is at some point when these 23 bolts were removed, there was something that ignited, the hydrogen either escaped or something ignited the hydrogen within the generator unit and that was what would cause the explosion?

A. We believe that the hydrogen escaped the generator prior to the ignition occurring.

Q. There is a seal between the cover and the actual face of the generator unit?

A. Yes.

Q. Is it a rubber seal?

A. It's some sort of gasket material. I don't know what the material is.

Q. In any case, the mechanism of the escape would be the removal of the bolts at some point, gas would have sufficient ability to come out from behind the cover; is that correct? You want me to rephrase that question?

A. Would you, please?

Q. The cover, when it's installed properly, prevents the gas from coming out of the generator unit?

A. Yes.

Q. At some point when the bolts were being removed, is it TECO's position that the hydrogen gas then escaped from around the seal of the cover as the cover was being removed?

A. We believe that that access cover became disattached, unattached from the generator housing and that allowed the gas to escape.

Q. One bolt remained on the cover; is that correct?

A. We only recovered 23 of the 24 bolts. What happened to the last one is unclear.

Q. And then to state the obvious but to get it on the record, I take it hydrogen gas is explosive?

A. Yes.

Q. And some mechanism ignited the free gas and that's what caused the explosion?

A. Hydrogen is explosive in certain ranges of concentration with oxygen. If the oxygen levels are too high, it's not explosive. If the oxygen levels are too low, it's not explosive, but there is a band in which hydrogen is an explosive gas.

Q. And hydrogen is used to cool the generator; is that correct?

A. That's correct.

Q. Is there some other gas that is nonexplosive in concentrations with oxygen that could be used to cool the generator?

A. In generators of this size, the only commercial offerings that are available are hydrogen-cooled generators that I'm aware of.

Q. Where were the maintenance people who were doing the electrical testing, where were they physically located the morning of the explosion?

A. They were located one floor below the turbine operating deck, the floor we call the

mezzanine. It's between the basement and the turbine deck.

Q. And what were they doing?

A. They were megger testing the generator.

Q. In order to perform the megger test, is it necessary that at any point they be on the floor where the generator unit is actually located?

A. Not that I'm aware of.

Q. Do you know whether any of these electrical workers attended the briefing of the maintenance supervisor?

A. Not that I'm aware of.

Q. Does TECO have any procedures -- let me back up and withdraw that.

The morning of April 8, did TECO have any procedures requiring that the supervisors for the various disciplines coordinate with each other prior to maintenance proceeding; for instance, the maintenance supervisor coordinating with the electrical testing supervisor?

A. There's not a requirement for a formal coordination. That coordination is part of their normal course of work. It's expected to be done, but it's not formalized in a structured procedure.

Q. You had used earlier the term "tagging

supervisor"?

A. Yes.

Q. Is that a correct term? Did I get that right?

A. Yes.

Q. The tagging supervisor the morning of April 8, was that the same person as the maintenance supervisor?

A. No. The tagging supervisor is a member of the operating crew.

Q. And under the TECO procedures that existed at that time, what was his responsibility in regards to tagging as to the generator?

A. A pre-tagging request had been submitted to the tagging supervisor, which indicated to him that when the testing, the electrical testing of the generator was completed, that this maintenance crew requests that the generator be tagged.

His responsibility would be at such time as it was appropriate to tag the generator, that he would be responsible for physically verifying that all the devices associated with the master tag on the generator had indeed been tagged and the equipment was safe, which would have included the purging of the generator.

And once he had made that verification, the master tag verifying that all those -- all that equipment and those systems were safe would have been hung on the master tag board with the name of the supervisor -- maintenance supervisor requesting the system to be tagged affixed to the tag.

Q. And it would have been the maintenance supervisor's responsibility to go to the tagging supervisor and ask him to tag the equipment?

A. It can occur that way, or the request was already there through this pre-tagging request that had been submitted prior to the outage starting.

Q. Do you know whether the maintenance supervisor did, in fact, ever go to the tagging supervisor and ask that the generator be tagged out?

A. Not that I'm aware of. The feedback from the supervisor's interview was that he was aware that the electrical testing was still proceeding and therefore had no reason to attempt to get the machine tagged.

MR. DAVIDSON: Are the names of the employees who were on the maintenance crew available to me, or is that something that you want

to maintain confidential as well?

MR. WILLIS: Let's treat that under the same agreement.

MR. DAVIDSON: The same agreement we had for the supervisor.

MR. WILLIS: Yes.

BY MR. DAVIDSON:

Q. And just so I'm clear, I think you may have answered this, but the Generator Unit No. 6 was not tagged out the morning of April 8; is that correct?

A. That's correct.

Q. Is there any type of gauge or meter or indicator of any kind in the vicinity of Unit 6 that would tell people in the vicinity of that unit whether there was or was not hydrogen gas within the unit?

A. No.

Q. Is there now?

A. No.

Q. Do any of the other units have such gauges or meters or indicators?

A. No, they don't.

Q. The morning of April 8, did the generator unit have any markings or warning signs as to

indicate that the unit contained hydrogen gas?

A. Not that I'm aware of.

Q. Did it have any markings to indicate that there were explosive or flammable materials or gases, dangerous substances within the unit?

A. I know that associated with the hydrogen storage and piping systems, there certainly are signs and indications of hydrogen and flammable mixture and that sort of thing. On the generator proper, I'm not aware of any markings.

Q. And there were no markings there yesterday either, were there?

A. Not that I saw.

Q. What was it that the maintenance crew was there to do that morning? What was their -- what was their goal?

A. The objective of the maintenance outage was to conduct a complete disassembly and maintenance of the high pressure turbine, the front standard. And with respect to the generator, the intent was to remove the generator rotor to do a complete inspection of the generator and make repairs as necessary.

Q. And under TECO's normal procedures, the hydrogen would have been purged from the generator

well before the morning of the 8th under the normal course of events; is that right?

A. It's a function of the electrical testing that has to be completed before you really understand the scope of work that you need to do in the generator. This testing cannot be done once the generator is disassembled. So that has to be completed. And depending on how long that testing takes, that dictates the other actions, the other sequence of actions that occur in the maintenance job.

Q. Let me show you what we'll mark as Exhibit 2. The cover sheet on this Exhibit 2 says "OSHA Report on TECO's Gannon Plant Explosion." Do you see that?

A. Yes, sir.

Q. And it's dated October 7, '99. I presume that's the time it probably came off the Internet or something. I don't know. Have you seen this report prior to today?

A. I've seen the information that's referred to in here. I have not seen it presented in the form that it exists in this exhibit.

Q. You saw it in a different format?

A. Yes.

Q. And what was the purpose for your having seen that report before? Was it part of your normal duties with TECO?

A. Yes.

Q. A report by OSHA would be something that you would normally review in your duties at least as it related to the plants under your supervision?

A. Yes.

MR. DAVIDSON: Thank you. No other questions.

MR. KEATING: Could I be permitted two more questions? I've got two short ones.

EXAMINATION

BY MR. KEATING:

Q. How would the hydrogen have safely been purged from the generator during the course of the maintenance outage?

A. When it's the testing has been completed and it's time to purge the hydrogen, it's done by introducing carbon dioxide into the generator to force the hydrogen out the hydrogen venting system, which takes the hydrogen CO2 mixture up through vents in the roof where it's safely vented to the atmosphere. We use CO2 for venting to prevent the hydrogen from coming into contact with air.

Once we've determined that the hydrogen concentrations in the gas being vented at the roof contain *no* hydrogen, then we proceed to purge the CO2 from the generator using air. And then when we reintroduce the hydrogen, the process is reversed.

Q. You responded to one of Mr. Davidson's questions that there is no hydrogen pressure gauge on the unit or there's not one on the exterior of the unit that the maintenance crew -- that would be visible to the maintenance crew?

A. There's not one in the vicinity of the Gannon 6 generator. There are pressure gauges on the hydrogen system for Gannon 6 that are located in the basement.

Q. Are those -- on that type of generating equipment, is an exterior hydrogen gauge that would have been on the unit itself, is that something that's available from the manufacturer?

A. It's available. I'm not aware of any generator either in our system or in other people's systems that have those kind of gauges at the generator.

Q. OSHA doesn't require that?

A. No.

Q. One other question. You mentioned that

prior to the explosion that morning, there was an announcement over the PA regarding the meggering test. To the best of your knowledge, was that fact provided to OSHA? Was OSHA aware of that fact during its investigation?

A. I believe they were.

MR. KEATING: Thank you. That's all.

MR. DAVIDSON: Could I ask one more raised from his?

EXAMINATION

BY MR. DAVIDSON:

Q. Whose responsibility was it under TECO's procedures to do the purging of the hydrogen from the generator? Was that the maintenance crew's responsibility, or was there somebody else that does that?

A. That would be done as part of the tagging of the generator under the master tag. That's one of the components that has to be accomplished before that master tag can be hung. That would be done under the supervision of the tagging supervisor, which is on the operating crew, and the actual purging is done by the operators.

In addition to the -- I did leave out a step in responding to Mr. Keating's question on the

procedure. Once the hydrogen has been completely and safely vented from the generator, there is a physical piece of pipe in the supply system that leads to the generator that we call the spool piece, and that piece of pipe is physically removed and the supply line capped to ensure that hydrogen is not reintroduced into the machine prior to the time that we're ready to put the unit back in service.

So in addition to the tag, there's also a physical indication of the fact that it is physically disconnected from the hydrogen supply system.

Q. Where is that spool piece located in the piping supply line?

A. It's outside the building on the ground floor.

Q. Which side of the building is that on?

A. On the north side.

Q. North side.

MR. DAVIDSON: Thank you.

MR. HART: I have no questions.

(Whereupon, the deposition concluded at 11:10 a.m.)

SIGNATURE PAGE

This is to certify that I, CHARLES R. BLACK, have read the foregoing transcription of my testimony, page 1 through 79, given on October 29, 1999, in Docket No. 990001-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.

_____

CHARLES R. BLACK

Sworn to and subscribed before me this _____ day of _____, 1999

_____

NOTARY PUBLIC

State of _____

My Commission Expires:

CERTIFICATE OF COURT REPORTER

STATE OF FLORIDA)

: ss.

COUNTY OF PINELLAS)

I, Donna W. Everhart, CSR, RPR, CP, CM, Court Reporter and Notary Public in and for the State of Florida at Large, DO HEREBY CERTIFY that CHARLES R. BLACK was duly sworn by me.

I FURTHER CERTIFY that the foregoing deposition was taken before me at the time and place therein designated; that my shorthand notes were thereafter transcribed into this computer-assisted transcript under my supervision; and the foregoing pages numbered 1 through 79, inclusive, constitute a true and correct record of the testimony given by the deponent.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of the parties, nor financially interested in the foregoing action.

DATED this 3rd day of November, 1999.

Donna W. Everhart
CSR, RPR, CP, CM
Notary Public, State of Florida
Commission No.: CC 670687
My Commission Expires: 12/8/2001

Donna W. Everhart
MY COMMISSION # CC670687 EXPIRES
December 8, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

ERRATA SHEET

DOCKET NO.: 990001-EI
NAME: CHARLES R. BLACK
DATE: October 29, 1999
IN RE: Fuel and purchased power cost recovery clause and generating performance incentive factor

Instructions:
Please read the transcript of your deposition and make note of any errors in transcription on this page. Do not mark on the transcript itself. Please sign the transcript on page 80. Thank you.

Page	Line	Error or Amendment	Reason

21. Please explain the cause of the April 8, 1999, explosion which occurred at TECO's Gannon Unit 6.

A. Gannon Unit 6 was in the early phase of a planned maintenance outage that included work on the boiler, turbine and a generator inspection. As part of the generator inspection it was necessary to remove the generator rotor. During normal operations of the unit, the circulation of hydrogen gas cools the generator. During the initial phase of work prior to beginning generator disassembly, an access cover was removed while hydrogen was still inside the generator casing under pressure. When the cover was removed before the hydrogen was purged, hydrogen escaped into the turbine building. When the concentration of hydrogen and air reached the point of being an explosive mixture, the gas cloud ignited causing a flash fire and structural damage.

22. Please describe the actions taken by TECO to maintain the reliability of the remaining five units at the Gannon Plant after the explosion at Gannon Unit 6.

A. The company's immediate response and concern was for the safety of the employees. After the explosion, the installed safety systems on the units functioned properly, which allowed the units to shut down without any significant problems. The operators initially purged the hydrogen from the remaining generators to minimize the risk of any further fire or explosions. To ensure the units could be returned to service safely, damage assessment teams from within and outside the company began inspections as early as two hours after the incident. Units 1 through 4 had only minor impacts. The two main areas of concern were dust and debris. Turbine rupture diaphragms had to be replaced on the turbines. In all aspects the units responded as expected and there were no collateral damage to the boilers or turbines as a result of the accident. The units were safely returned to service as soon as these inspections were complete. This was within several days of the accident as noted in the response to Interrogatory No. 23.

Gannon Unit 5 had more direct physical damage to the electrical equipment since it is located adjacent to Unit 6. All safety systems worked properly and the operators responded well to ensure the safety of the equipment. No damages occurred to the boiler or turbine as result of the explosion. Again, detailed inspections were made of all of the equipment and structures immediately following the incident. Motors, switchgear cables, and other equipment were repaired and/or sent out for inspection and cleaning. Equipment was secured and or covered where necessary to minimize damage from the elements.

23. For Gannon Units 1 through 6, please indicate when each unit was placed, or is expected to be placed, back into service.

A. Four of the six units were placed back into service very shortly after the explosion due to minimal impacts and the proper operation of various back-up systems.

Gannon Unit 1 was returned to service on April 10
Gannon Unit 2 was returned to service on April 10
Gannon Unit 3 was returned to service on April 10
Gannon Unit 4 was returned to service on April 12[1]
Gannon Unit 5 was returned to service on May 16[2]
Gannon Unit 6 was returned to service on June 22[2] [3]

---

[1] Gannon Unit 4 was later removed from service on April 23 due to a collector ring failure determined to be a result of the April 8 explosion debris. It was returned to service on May 10.

[2] Gannon Unit 6 was in an extended 58-day maintenance outage at the time of the incident. The explosion repairs, clean up and investigation extended the outage approximately 4 weeks.

[3] Additional time was taken and the outage was extended to conduct other maintenance not associated with the accident while Unit 5 and 6 were already out of service. Had it not been for this, Unit 5 would have gone back in service on April 30 and Unit 6 would have gone back in service on June 20.

24. For Gannon Units 1 through 6, please indicate for each unit the amount of energy and capacity made unavailable as a result of the unit being taken out of service due to the explosion at Unit 6.

A. The estimated amount of energy and capacity from Tampa Electric's generating units made unavailable as a result of the Gannon Unit 6 explosion is calculated in the attached table. The capacity and energy made unavailable was determined by first estimating the capacity and energy that was available independent of the Gannon Unit 6 accident. Accordingly any partial or full outages of each generating unit that were not the result of the accident were used to establish the point of reference. The impact of the resulting accident on the availability of the generating units at Gannon was then estimated at 100 percent capacity factor to determine the magnitude and duration of the capacity made unavailable over the three-month period beginning April 1 through June 30. A projected capacity factor was then applied to estimate the energy that was effectively displaced since none of this units operate at a 100 percent capacity factor.

INTERROGATORY NO. 24

Energy and Capacity Made Unavailable Due to the Gannon 6 Accident

UNIT	(A) PROJECTED CAPACITY (MW)	(B) CAPACITY MADE UNAVAILABLE (MW)	(C) ESTIMATED AVAILABILITY INCLUDING ALL OUTAGES (HRS)	(D) ACCIDENT RELATED UNAVAILABILITY (HRS)	(E) ESTIMATED UNAVAILBLE ENERGY ASSUME 100% CAPACITY FACTOR (MWH)	(F) ESTIMATED CAPACITY FACTOR	(G) ESTIMATED UNAVAILBLE ENERGY USING PROJECTED CAPACITY FACTOR (MWH)	(H) DATES UNIT NOT AVAILABLE RESULTING FROM THE ACCIDENT
Gannon 1	99	99	2,064	72	7,128	0.37	2,637	Apr 8-10
Gannon 2	93	93	2,064	72	6,696	0.27	1,808	Apr 8-10
Gannon 3	145	145	1,944	72	10,440	0.46	4,802	Apr 8-10
Gannon 4	169	169	1,584	528	89,232	0.59	52,647	Apr 8-11 & Apr 23-May10
Gannon 5	227	227	1,104	552	125,304	0.69	86,460	Apr 8-30
Gannon 6	362	362	192	720	260,640	0.69	179,842	May 24-June 22
						TOTAL	328,196	

(A) Based on projected summer net capabilities filed in the 1999 Ten-Year Site Plan.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 2nd SET OF INTERROGATORIES
INTERROGATORY NO. 24
PAGE 2 of 2
REVISED: 8/19/99

25. For Gannon Units 1 through 6, please indicate for each unit the amount of unavailable energy and capacity identified in response to Interrogatory No. 4 (sic) that was replaced by other TECO generating units.

A. The need to replace unavailable energy and capacity is directly related to the system demand and energy requirements. The system impact of the Gannon accident was a function of other Tampa Electric resources and system needs for purchased power.

An estimate of unavailable energy was made by comparing the actual system energy generated and purchased to that estimated using actual hourly load data as well as actual outage data for all non-Gannon units. For the estimated case in which the Gannon accident did not occur, the Gannon unit outages were assumed to be what was planned prior to the Gannon Unit 6 accident. The analysis was conducted for the period of April through June of 1999. Other planning assumptions used in the analysis were identical to those used in Tampa Electric's 1999 fuel adjustment filing and were not adjusted to reflect actual conditions.

It is estimated that a total of 169 MWH of Gannon Station's generation was replaced with other Tampa Electric Generating units as a result of the Gannon Unit 6 accident. Approximately 144 MWH of the estimated 169 MWH was energy that Gannon Units 1 through 3 produced to replace energy made unavailable by Gannon Units 4 , 5 and 6.

Tampa Electric has initiated a study that will benchmark its system for the months of April, May and June of 1999. This study will use actual hourly load data, unit outage data, actual purchases, and actual unit operating data for the study period. The results of this study will provide more precise results of the Tampa Electric units and purchase power that were used to replaced energy made unavailable as the result of the Gannon explosion. These results will be provided to the Commission and Staff.

26. Please indicate for each unit the incremental fuel costs associated with replacing the unavailable energy from Gannon Units 1 through 6 with other TECO generating units.

A. An estimated of the incremental fuel and purchased power expense is provided in the attached table. This estimate compared actual fuel and purchased power expenses to that estimated using actual hourly load data and outage data for non-Gannon Units. For the estimated case in which the Gannon accident did not occur, the Gannon Unit outages were assumed to be what was planned prior to the Gannon Unit 6 accident. The analysis was conducted for the period of April through June of 1999. Other planning assumptions used in the analysis were identical to those used in Tampa Electric's 1999 fuel adjustment filing and were not adjusted to reflect actual conditions.

Tampa Electric has initiated a study that will benchmark its system for the months of April, May and June of 1999. This study will use actual hourly load data, unit outage data, actual fuel and purchase power data and actual unit operating data for the study period. The results of this study will provide more precise results of the incremental fuel and purchase power expense that occurred as a result Gannon explosion. These results will be provided to the Commission and Staff.

INTERROGATORY NO. 26

April - June 1999

	(A) Estimated Replacement Energy (GWH)	(B) Estimated Capacity (MW)	(C) Estimated Fuel or Purchase Power Expense ($/MWH)	(D) Estimated Gannon Station Fuel Expense ($/MWH)	(E) Estimated Fuel Expense Differential ($/MWH)	(F) Estimated Incremental Fuel Expense ($000)
BIG BEND & GANNON CTS TOTAL	7.9	138	52.68	23.16	29.52	232.94
HOOKERS POINT STATION TOTAL	13.2	204	35.59	23.16	12.43	164.27
GANNON STATION TOTAL	143.9	1095	24.13	23.16	0.97	139.58
BIG BEND STATION TOTAL	0.0	1712	19.35	23.16	(3.81)	0.00
PHILLIPS STATION TOTAL	4.2	34	30.70	23.16	7.54	31.94
POLK UNIT 1 TOTAL	0.0	250	25.51	23.16	2.35	0.00
				Total Incremental Fuel Expense of Energy Replaced by Non-Gannon Generating Units		568.74
PURCHASES TOTAL	159.0		48.04	23.16	24.88	3,955.90
				Total Incremental Purchase Power Expense of Energy and Capacity Replaced by Purchase Power and Non-Gannon Generating Units		4,524.64
ESTIMATED UNAVAILABLE ENERGY DUE TO GANNON 6 ACCIDENT	(328.2)					
TOTAL FIRM ENERGY UNSERVED	0.0					

Note: Estimated purchase power expense cost includes energy and capacity costs.
Note: Incremental fuel expense is the product of estimated replacement energy and estimated fuel differential.
Note: The estimated Gannon fuel expense in col (C) reflects the weighted average of the Gannon units based on actual generation.
Note: The estimated Gannon fuel expense in col (D) reflects the weighted average of the units based on projected generation of the units.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 2nd SET OF INTERROGATORIES
INTERROGATORY NO. 26
PAGE 2 of 2
REVISED: 8/19/99

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 2nd SET OF INTERROGATORIES
INTERROGATORY NO. 27
PAGE 1 of 1
REVISED: 8/19/99

27. Please indicate for each unit the incremental cost associated with replacing the unavailable energy and capacity from Gannon Units 1 through 6 with purchased power.

A. The incremental cost of purchase power that was required to replace unavailable energy and capacity due to the Gannon accident has been provided in the response to Interrogatory No. 26.

Exhibit No. ____ (WLB-2), Document No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 34
COMPANY/ WITNESS: Brown
DATE 11-22-99

THIRD AMENDMENT

DATED AS OF September 15, 1999

TO THE

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY

BETWEEN

HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION),

AND

TAMPA ELECTRIC COMPANY

Dated as of July 27, 1989,

As Previously Amended

SEPTEMBER 28, 1989 and

DECEMBER 13, 1990

THIRD AMENDMENT TO AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED AND TAMPA ELECTRIC COMPANY

This Third Amendment ("Third Amendment") to the Agreement for Sale and Purchase of Capacity and Energy Agreement between Hardee Power Partners Limited and Tampa Electric Company (hereinafter referred to as the "Tampa Agreement") is made and entered into this 15th day of September 1999, by and between Hardee Power I, Inc., acting as General Partner on behalf of Hardee Power Partners Limited, a Florida limited partnership having its principal place of business at 702 N. Franklin Street, Tampa, Florida 33602, as assignee of TECO Power Services Corporation (hereinafter referred to as "HPP") and Tampa Electric Company, a Florida corporation (hereinafter referred to as "Tampa") having its principal place of business at 702 N. Franklin Street, Tampa, Florida 33602. All capitalized terms used in this Amendment shall be as defined in the Tampa Agreement as amended herein.

WITNESSETH

WHEREAS, in 1989, HPP and Tampa entered into the Tampa Agreement pursuant to which HPP is obligated to supply to Tampa 295 MW of capacity and associated energy from the 1993 Non-Coal Facilities; and

WHEREAS, concurrently with the execution of the Tampa Agreement, HPP and Seminole Electric Cooperative, Inc. ("Seminole") entered into an Agreement for Sale and Purchase of Capacity and Energy (as amended, the "Seminole Agreement"), pursuant to which HPP is obligated to supply to Seminole 295 MW of capacity and energy, all of which is to come from the 1993 Non-Coal Facilities; and

WHEREAS, the Seminole Agreement provides that in the event Seminole constructs its own 220 MW combined cycle generating plant on the Site, HPP will share the HPS Site Common Facilities (including facilities specifically listed in the Seminole Agreement) with Seminole based on Seminole being responsible for an equitable share of the cost of necessary modifications, expansions or adjustments of the facilities necessary to support such capacity and an equitable share of any increase in operation and maintenance costs with respect to such HPS Site Common Facilities; and

WHEREAS, Seminole has decided to construct a 488 MW combined cycle generating facility on the Site, rather than a 220 MW facility; and

WHEREAS, Seminole's construction of a 488 MW facility at the Site will result in Seminole's increased utilization of the HPS Site Common Facilities; and

WHEREAS, Tampa and HPP desire to amend the Tampa Agreement to reflect the increased utilization of the HPS Site Common Facilities by Seminole as a result of the construction of the 488 MW facility at the Site;

NOW, THEREFORE, in consideration of the foregoing premises and of the mutual benefits to be obtained from the covenants herein, the Parties hereby agree as follows:

ARTICLE I.

DEFINITIONS

Section 1. 1. Additional Definitions – The following additional definitions are hereby added to the Tampa Agreement and all subsection numbering shall be deemed revised accordingly:

> **"Access Roads"** shall mean Front Access Road and the Cooling Reservoir Access Road at the Site.

"Cooling Reservoir" is referred to as the "cooling pond" in Section 7.7 and shall mean the nominal 570 acre reservoir at the Site, including but not limited to the berm, the spillway, the reservoir overflow and weir, the box culvert, and the road from the Cooling Reservoir Access Road to the spillway, the associated ground water monitoring wells for the reservoir, and all improvements to the foregoing; but excluding the capital additions to the Cooling Reservoir made solely by Seminole, which additions shall be part of HPS #3.

"Cooling Reservoir Access Road" shall mean the access road from HPS #1 and #2 extending north to the Cooling Reservoir berm and overflow weir, as it may be modified from time to time.

"FDEP" shall mean the State of Florida Department of Environmental Protection.

"Front Access Road" shall mean the road from the Site entrances on the Brewster-Fort Green Road, extending west and south to the turn-off for HPS #3 and further south to the Switchyard within the HPS existing fence, as it may be modified from time to time.

"Hardee Power Station, Unit #3" or "HPS #3" shall mean the 488 MW combined cycle generating facility proposed to be built by Seminole on the Site. HPS #3 is also designated and known as the "Payne Creek Generating Station."

"Hardee Power Station, Units #1 and #2" or "HPS #1 and #2" shall mean the generating facilities comprising the 1993 Non-Coal Facilities and, to the extent that they have been constructed, the 2003 Capacity Additions.

"HPP" shall mean both HPP and, solely when referring to agreements which have been assigned to HPP, its legal predecessor in interest, TPS.

"HPS Site Common Facilities Capacity Charge Adjustment" shall mean the amount by which the Monthly Capacity Charge is adjusted each month pursuant to Section 6.4.9 to reflect the HPS Site Common Facilities Capacity Charge.

"HPS Site Common Facilities" shall mean the following facilities: (a) the Access Roads, (b) the Cooling Reservoir, (c) the Natural Gas Pipeline, (d) the Switchyard, (e) the Site and (f) the Water Wells and Pumps; all of which are among the common facilities listed and contemplated to be shared by HPS #1 and #2 and HPS # 3; provided that any capital additions to the HPS Site Common Facilities made solely by Seminole solely for HPS #3 shall not be a part of the HPS Site Common Facilities; and capital additions to the HPS Site Common Facilities made solely by HPP solely for the 2003 Capacity Additions shall be part of the 2003 Capacity Additions and not part of the HPS Site Common Facilities.

"HPS Site Common Facilities Capacity Charge" shall mean the component of the HPS Site Common Facilities Capacity Charge Adjustment that is the result of Seminole's equitable share of the HPS Site Common Facilities as a result of the

construction of HPS #3 and Tampa's equitable share of the HPS Site Common Facilities as a result of the construction of 2003 Capacity Additions.

"HPS Site Common Facilities Energy Charge" shall mean the charges which are included in the Monthly Energy Charge pursuant to Section 6.5.4 which are the result of Seminole's equitable share of the Fixed Operation and Maintenance Cost and Variable Operation and Maintenance Cost associated with the HPS Site Common Facilities as a result of the construction of HPS #3 and Tampa's equitable share of the Fixed Operation and Maintenance Cost and Variable Operation and Maintenance Cost associated with the HPS Site Common Facilities as a result of the construction of the 2003 Capacity Additions.

"HPS #3 Capacity Charge Adjustment Effective Date" shall mean the first day of the month following receipt of final approval of the modification of the conditions of certification to allow the construction and operation of HPS #3 from the FDEP.

"HPS #3 Commercial Operation Date" shall mean the "Provisional Acceptance Date," as defined in the HPS #3 Construction Contract, currently scheduled for January 1, 2002. The Provisional Acceptance Date shall mean the date when construction of HPS #3 is complete and the thermal performance and environmental emissions of the plant have been demonstrated.

"HPS #3 Construction Contract" shall mean the Engineering, Procurement and Construction Agreement by and among Seminole, Siemens Westinghouse Power Corporation and Overland Contracting, Inc., dated as of December 10, 1998, relating to HPS #3.

"HPS # 3 Construction Release" shall mean the date on which the construction contractor under the HPS #3 Construction Contract has equipment, material and labor on the Site ready and organized to commence construction of HPS #3. The date of HPS # 3 Construction Release is currently scheduled for March 1, 2000.

"HPS #3 Energy Charge Effective Date" shall mean the date which is three hundred and thirty (330) days from the HPS #3 Construction Release.

"Natural Gas Pipeline" shall mean the existing nine and seven-tenths (9.7) mile, eighteen (18) inch natural gas pipeline and associated meter station facilities serving the Site, located between the Hardee Power Station and the Florida Gas Transmission Corporation's Sarasota lateral located near the intersection of State Road 37 and Polk County Road 630, including the piping and natural gas filter station on the Site, and all improvements to the foregoing; but excluding the capital additions made solely by or for Seminole to the Natural Gas Pipeline, which additions shall be part of HPS #3.

"Switchyard" shall mean the electrical switching facilities to the east of the HPS #1 and #2 and south of the location of HPS #3, including the breakers, bus, relay and protection equipment, control building, support structures and foundations,

and all improvements to the foregoing; but excluding the capital additions made solely by Seminole for HPS #3 to the Switchyard, which additions shall be part of HPS #3 and further excluding all capital additions made solely by HPP for the 2003 Capacity Additions to the Switchyard, which additions shall be part of the 2003 Capacity Additions.

"TPS" shall mean TECO Power Services Corporation, a wholly-owned subsidiary of TECO Energy, Inc.

"Water Wells and Pumps" shall mean the three wells and associated electric motor driven pumps which currently provide makeup water to the Cooling Reservoir and process water to HPS #1 and #2, including the pumps, piping to the Cooling Reservoir, control and metering equipment, and all improvements to any of the foregoing; but excluding the capital additions made solely by Seminole to the Water Wells and Pumps, which additions shall be part of HPS #3.

Section 1.2. Amended Definitions – The following definitions in the Tampa Agreement shall be amended as set forth below and likewise shall be subject to renumbering as provided in Section 1.1:

"Fair Market Value" of any property as of any date shall mean the cash price obtainable in an arm's-length sale between an informed and willing buyer (under no compulsion to buy) and an informed and willing seller (under no compulsion to sell) of the property in question. If the Parties are unable to agree upon a determination of Fair Market Value, such Fair Market Value shall be determined in accordance with the Appraisal Procedure. With respect to determination of Fair Market Value of all or any part of the HPS Site Common Facilities, such value shall be determined by a third party other than Seminole who is free to use and remove the property without regard to this Agreement.

"Fixed Operation and Maintenance Cost" shall mean the cost associated with the day-to-day staffing of the Hardee Power Station, rents and maintenance of the plant structures, as calculated pursuant to Appendices F, J and X.

"Hardee Power Station" shall mean collectively HPS #1 and #2 and HPS #3.

"REA" or "RUS" shall mean the Rural Electrification Administration and its successor agency, the Rural Utilities Service of the U.S. Department of Agriculture, and any further successor agency.

"Variable Operation and Maintenance Cost" shall mean the cost associated with steam and electricity production and the maintenance of boiler, steam and electric plant, including generation unit start-up costs not otherwise allocated, as calculated pursuant to Appendices G, K and Y.

ARTICLE II.

AMENDMENTS REGARDING OPERATIONS

Section 2.1 Appendix A – Appendix A to the Tampa Agreement shall be hereby amended with the replacement Appendix A attached to this Third Amendment.

ARTICLE III.

AMENDMENTS TO CHARGING, BILLING AND PAYMENTS

Section 3. 1 Monthly Capacity Charge – Section 6.4 of the Tampa Agreement shall be amended to read as follows:

> 6.4 Monthly Capacity Charge: The Monthly Capacity Charge shall be equal to the Monthly CT/CC Capacity Charge for the CT/CC Facilities. For the Monthly CT/CC Capacity Charge, during the period from the Date of Operations to the earlier of (a) the last day of the tenth Contract Year and (b) December 31, 2003, the Monthly CT/CC Capacity Charge shall be $1,137,250. During the period described in the preceding sentence through the remaining term of this Agreement, the Monthly CT/CC Capacity Charge shall be $1,184,917. All monthly capacity charges described in this Section 6.4 shall be subject to adjustment only as expressly provided for in this Agreement.

Section 3.2 HPS Site Common Facilities Capacity Charge Adjustment – The following Section 6.4.9 shall be added to the Tampa Agreement:

> 6.4.9 HPS Site Common Facilities Capacity Charge Adjustment: Commencing on the HPS #3 Capacity Charge Adjustment Effective Date and subject to Sections 6.4.9.1 through 6.4.9.4, the HPS Site Common Facilities Capacity Charge Adjustment shall be a credit of $19,494 to reflect the utilization of the HPS Site Common Facilities by HPS #3. Commencing on January 1, 2003 and subject to Section 6.4.9.1 through 6.4.9.4, the HPS Site Common Facilities Capacity Charge Adjustment shall be a credit of $20,320 to reflect the utilization of the HPS Site Common Facilities by HPS #3.
>
> 6.4.9.1 Termination of Use of HPS Site Common Facilities: At such time, if any, that Seminole permanently ceases to use all or any part of the HPS Site Common Facilities, the HPS Site Common Facilities Capacity Charge Adjustment shall be equitably adjusted to reflect such reduced usage. The Parties shall promptly prepare and execute the necessary amendments to this Agreement and HPP shall file such amendments with the FERC as are required. The adjustment of the HPS Site Common Facilities Capacity Charge Adjustment with

respect to HPS #3 shall be effective on the later of the first day of the month following written notice by HPP to Tampa that Seminole is permanently ceasing the use of such facilities at HPS #3 or the day on which the FERC has permitted such adjustment to go into effect.

6.4.9.2 Cancellation of HPS #3: If HPS #3 is canceled following the HPS #3 Capacity Charge Adjustment Effective Date, the HPS Site Common Facilities Capacity Charge Adjustment shall be adjusted accordingly. Such adjustment shall be effective on the later of the first day of the month following written notice by HPP to Tampa that HPS #3 has been canceled or the day on which the FERC has permitted such adjustment to go into effect. For purposes of this Section 6.4.9.2 and Section 6.5.3, HPS #3 shall be deemed "canceled" as the result of any action that cancels its construction altogether or delays the scheduled HPS #3 Commercial Operation Date by six (6) or more years beyond January 1, 2002.

6.4.9.3. Delay of HPS #3: Should either the HPS #3 Construction Release or the HPS #3 Commercial Operation Date be delayed for a period that results in a delay of the scheduled HPS #3 Commercial Operation Date by more than one (1) year but less than six (6) years from January 1, 2002, then the HPS Site Common Facilities Capacity Charge Adjustment with respect to the HPS #3 shall be suspended for a period equal to the scheduled delay. Such suspension of the HPS Site Common Facilities Capacity Charge Adjustment shall be effective on the later of the first day of the month following written notice by HPP to Tampa that HPS #3 has been delayed or the day on which the FERC has permitted such suspension to go into effect.

6.4.9.4 Future Adjustments of HPS #3: If HPS #3 is reconfigured or adjusted in its nominal electrical capacity capability and/or in its use of the HPS Site Common Facilities, the HPS Site Common Facilities Capacity Charge Adjustment shall be equitably adjusted and HPP shall promptly file any necessary documents with the FERC to carry out the intent of the Parties under this Section.

Section 3.3 Monthly Energy Charge – Certain parts of Section 6.5 of the Tampa Agreement and Appendices F, G, J, K, T and U to the Tampa Agreement shall be amended to reflect changes in the Monthly Energy Charge. In addition, Section 6.5.3 and Appendices X and Y shall be added to the Tampa Agreement.

Section 3.3.1 Monthly Energy Charge – Section 6.5 of the Tampa Agreement shall be amended to read as follows:

6.5. Monthly Energy Charge: The Monthly Energy Charge shall be comprised of (i) the Monthly Combustion Turbine Cost, (ii) the Monthly

Combined Cycle Cost and (iii) the HPS Site Common Facilities Energy Charge. Costs and allocations of costs shall be determined in accordance with the records and accounting system of HPP. Such records and accounting system will be kept according to generally accepted utility accounting practices, including the FERC Uniform System of Accounts.

Section 3.3.2 Monthly Combustion Turbine Cost – Section 6.5.1(b) of the Tampa Agreement shall be amended to read as follows:

(b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the occurrence of the HPS #3 Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded) allocated to the CT unit as calculated pursuant to Appendix F and (ii) the Tampa portion of the Delivery Month Variable Operation and Maintenance Costs (provided, however, that, upon the occurrence of the HPS #3 Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded) allocated to the CT unit as calculated pursuant to Appendix G less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by the CT unit for Tampa during the previous twelve (12) month period ending with the Delivery Month bears to the total net energy generated by such unit during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales);

Section 3.3.3 Monthly Combined Cycle Cost – Section 6.5.2(b) of the Tampa Agreement shall be amended to read as follows:

(b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the occurrence of the HPS #3 Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded) allocated to the Combined Cycle Units as calculated pursuant to Appendix J and (ii) the Tampa portion of the Delivery Month Variable Operation and Maintenance Costs (provided, however, that, upon the occurrence of the HPS #3 Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded) associated with the Combined Cycle Units as calculated pursuant to Appendix K less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by the Combined Cycle Units for Tampa during the previous twelve (12) month period ending with the Delivery Month bears to the total net energy generated by the Combined Cycle Units during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales);

Section 3.3.4 HPS Site Common Facilities Energy Charge – The following Section 6.5.3 shall be added to the Tampa Agreement:

> 6.5.3 HPS Site Common Facilities Energy Charge: Commencing on the HPS #3 Energy Charge Effective Date and continuing through the term of this Agreement, the HPS Site Common Facilities Energy Charge shall include an allocation to reflect Seminole's equitable share of the Delivery Month Fixed Operation and Maintenance Cost and the Delivery Month Variable Operation and Maintenance Cost associated with the utilization of the HPS Site Common Facilities for HPS #3, as calculated pursuant to Appendices X and Y. The HPS Site Common Facilities Energy Charge shall also be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4.

ARTICLE IV.

EFFECTIVE DATE

Section 4.1 Effective Date – This Third Amendment shall be effective on the later to occur of (i) the date on which this Third Amendment and the Third Amendment to the Seminole Agreement are accepted for filing by the FERC and allowed to become effective and (ii) the date on which the Third Amendment to the Seminole Agreement is approved by the Administrator of the Rural Utilities Service.

IN WITNESS WHEREOF, the Parties hereto have caused this Third Amendment to the Tampa Agreement to be executed by their fully authorized officers, and copies delivered to each party, as of the first day above written.

HARDEE POWER I, INC.
acting as General Partner of
HARDEE POWER PARTNERS LIMITED

WITNESSES:

By: _____

Title: President

TAMPA ELECTRIC COMPANY

WITNESSES:

By: _____

Title: President

APPENDIX F

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBUSTION TURBINE FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Cost" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance (Sum of Lines 1 Through 14; See Note 4)		
16	Percent Allocable to Tampa: 40%.		

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit and shall exclude all Fixed Operation and Maintenance Cost associated with the HPS Site Common Facilities upon the occurrence of the HPS #3 Energy Charge Effective Date. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX G

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBUSTION TURBINE VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Cost" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance (Appendix F, Line 15)	
17	Total Variable Operation & Maintenance (Line 15 – Line 16)	

18 Operation & Maintenance Allocated to Off-System Sales

19 Total Variable O&M To Be Allocated (Line 17 – Line 18)

20 Energy Generated by the CT Unit for Tampa During the Previous Twelve Month Period Ending With the Delivery Month

21 Total Energy Generated By the CT Unit During the Previous Twelve Month Period Ending With the Delivery Month

22 Energy Generated by the CT Unit for Off-System Sales During the Previous Twelve Month Period Ending With the Delivery Month

23 Total Net Energy Generated By the CT Unit Exclusive of Energy Generated for Off-System Sales (Line 21 – Line 22)

24 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 20 divided by Line 23)

25 Total Variable O&M Allocable to Tampa Associated With Tampa's Sales of Schedules A and B Interchange Service

26 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA ((Line 19 x Line 24) + Line 25)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit and shall exclude all Fixed Operation and Maintenance Cost and Variable Operation and Maintenance Cost associated with the HPS Site Common Facilities upon the occurrence of the HPS #3 Energy Charge Effective Date. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX J

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

COMBINED CYCLE
FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Cost" excluding fuel, identified in Section 6.5.2 (b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance (Sum of Lines 1 Through 14; See Note 4)		
16	Percent Allocable to Tampa: 40%.		

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the Combined Cycle unit and shall exclude all Fixed Operation and Maintenance Cost associated with the HPS Site Common Facilities upon the occurrence of the HPS #3 Energy Charge Effective Date. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX K

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBINED CYCLE VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Cost" excluding fuel, identified in Section 6.5.2 (b) shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance (Appendix J, Line 15)	
17	Total Variable Operation & Maintenance (Line 15 - Line 16)	

18 Operation & Maintenance Allocated to Off-System Sales

19 Total Variable O&M To Be Allocated (Line 17 - Line 18)

20 Energy Generated by the Combined Cycle Units for Tampa During the Previous Twelve Month Period Ending With the Delivery Month

21 Total Energy Generated By the Combined Cycle Units During the Previous Twelve Month Period Ending With the Delivery Month

22 Energy Generated by the Combined Cycle Units for Off-System Sales During the Previous Twelve Month Period Ending With the Delivery Month

23 Total Net Energy Generated By the Combined Cycle Units Exclusive of Energy Generated for Off-System Sales (Line 21 – Line 22)

24 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 20 divided by Line 23)

25 Total Variable O&M Allocable to Tampa Associated With Tampa's Sales of Schedules A and B Interchange Service

26 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA ((Line 19 x Line 24) + Line 25)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the Combined Cycle unit and shall exclude all Fixed Operation and Maintenance Cost and Variable Operation and Maintenance Cost associated with the HPS Site Common Facilities upon the occurrence of the HPS #3 Energy Charge Effective Date. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX T

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

REPLACEMENT OF COMBUSTION TURBINE PROPERTY UNITS EXPENSE

For purposes of this Agreement, the "Delivery Month Fixed Charges for Replacement Property Units" identified in Section 6.5.1 (c) shall be determined as follows:

Line	Description
1	Expenditures (Net of Salvage Value) for Replacement of Property Units of the CT 2A – Current Month (Note 1)
2	Expenditures for Replacement of Property Units from Inception of Agreement to End of Prior Month (Per Prior Bill – Line 3)
3	Cumulative Expenditures for Replacement of Property Units of the CT 2A from Inception of Agreement to End of Current Month (Line 1 + 2)
4	Fixed Charge Rate (14.67% Annually/12): 1.222%
5	Current Month Fixed Charges for Property Units Replaced on the CT 2A (Line 3 x Line 4)
6	Percent Allocable to Tampa: 40%
7	Delivery Month Fixed Charges for Property Units Replaced on the CT 2A and Allocable to Tampa (Line 5 x Line 6)

Note 1: Includes only those capitalized expenditures for the replacement of property units which existed, per design specifications, on the date that the CT 2A was placed in commercial operation, or as subsequently modified by mutual agreement of the Parties or as otherwise determined by the Operating Committee from time to time. HPP shall define the property units and submit such definitions to the Operating Committee for review and approval.

APPENDIX U

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

REPLACEMENT OF COMBINED CYCLE PROPERTY UNITS EXPENSE

For purposes of this Agreement, the "Delivery Month Fixed Charges for Replacement Property Units" identified in Section 6.5.2 (c) shall be determined as follows:

Line	Description
1	Expenditures (Net of Salvage Value) for Replacement of Property Units of the Combined Cycle Units - Current Month (Note 1)
2	Expenditures for Replacement of Property Units from Inception of Agreement to End of Prior Month (Per Prior Bill – Line 3)
3	Cumulative Expenditures for Replacement of Property Units of the Combined Cycle Units from Inception of Agreement to End of Current Month (Line 1 + 2)
4	Fixed Charge Rate (14.67% Annually/12): 1.222%
5	Current Month Fixed Charges for Property Units Replaced on the Combined Cycle Units (Line 3 x Line 4)
6	Percent Allocable to Tampa: 40%
7	Delivery Month Fixed Charges for Property Units Replaced on the Combined Cycle Units and Allocable to Tampa (Line 5 x Line 6)

Note 1: Includes only those capitalized expenditures for the replacement of property units which existed, per design specifications, on the date that the Combined Cycle Unit in question was placed in commercial operation, or as subsequently modified by mutual agreement of the Parties or as otherwise determined by the Operating Committee from time to time. HPP shall define the property units and submit such definitions to the Operating Committee for review and approval.

APPENDIX X

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

HPS SITE COMMON FACILITIES

FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Cost associated with the utilization of the HPS Site Common Facilities" excluding fuel, identified in Section 6.5.3 shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated with HPS Site Common Facilities (Sum of Lines 1 Through 14; See Note 4)		

16 Percent Allocable to Tampa commencing on the HPS #3 Energy Charge Effective Date: 28%.

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR HPS SITE COMMON FACILITIES (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Site Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX Y

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

HPS SITE COMMON FACILITIES

VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Cost associated with the utilization of the HPS Site Common Facilities" excluding fuel, identified in Section 6.5.3 shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With HPS Site Common Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance Associated With HPS Site Common Facilities (Appendix X, Line 15)	

17 Total Variable Operation & Maintenance Associated With HPS Site Common Facilities To Be Allocated (Line 15 – Line 16)

18 Energy Generated for Tampa from HPS #1 and #2 During the Previous Twelve Month Period Ending With the Delivery Month

19 Total Energy Generated from HPS #1 and #2 and HPS #3 During the Previous Twelve Month Period Ending With the Delivery Month

20 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 18 divided by Line 19)

21 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR HPS SITE COMMON FACILITIES (Line 17 x Line 20)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Site Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

FOURTH AMENDMENT

DATED AS OF September 15, 1999

TO THE

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY

BETWEEN

HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION),

AND

TAMPA ELECTRIC COMPANY

Dated as of July 27, 1989,

As Previously Amended

SEPTEMBER 28, 1989 and

DECEMBER 13, 1990

FOURTH AMENDMENT TO AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED AND TAMPA ELECTRIC COMPANY

This Fourth Amendment ("Fourth Amendment") to the Agreement for Sale and Purchase of Capacity and Energy Agreement between Hardee Power Partners Limited and Tampa Electric Company (hereinafter referred to as the "Tampa Agreement") is made and entered into this 15th day of September 1999, by and between Hardee Power I, Inc., acting as General Partner on behalf of Hardee Power Partners Limited, a Florida limited partnership having its principal place of business at 702 N. Franklin Street, Tampa, Florida 33602, as assignee of TECO Power Services Corporation (hereinafter referred to as "HPP") and Tampa Electric Company, a Florida corporation (hereinafter referred to as "Tampa") having its principal place of business at 702 N. Franklin Street, Tampa, Florida 33602. All capitalized terms used in this Amendment shall be as defined in the Tampa Agreement as amended herein.

WITNESSETH

WHEREAS, in 1989, HPP and Tampa entered into the Tampa Agreement pursuant to which HPP is obligated to supply to Tampa 295 MW of capacity and associated energy from the 1993 Non-Coal Facilities; and

WHEREAS, concurrently with the execution of the Tampa Agreement, HPP and Seminole Electric Cooperative, Inc. ("Seminole") entered into an Agreement for Sale and Purchase of Capacity and Energy (as amended, the "Seminole Agreement"), pursuant to which HPP is obligated to supply to Seminole 295 MW of capacity and energy, all of which is to come from the 1993 Non-Coal Facilities; and

WHEREAS, pursuant to the Tampa Agreement and the Seminole Agreement, Tampa, Seminole and HPP were granted certain rights to require the expansion of the 1993 Non-Coal Facilities to include the 2003 Capacity Additions; and

WHEREAS, by letter dated May 24, 1999, Seminole waived its option to require the construction of the 2003 Capacity Additions as provided for in the Seminole Agreement; and

WHEREAS, Tampa has exercised its option to require the construction of the 2003 Capacity Additions in two phases; and

WHEREAS, HPP is willing to finance, construct, operate and maintain such 2003 Capacity Additions pursuant to the rates, terms and conditions set forth herein; and

WHEREAS, HPP's construction of the 2003 Capacity Additions for Tampa will result in Tampa's increased utilization of the HPS Shared Common Facilities at the Site for which Tampa shall be responsible for an equitable share of the cost of necessary modifications, expansions, or adjustments of the facilities necessary to support such capacity and an equitable share of the operation and maintenance costs with respect to the HPS Shared Common Facilities; and

WHEREAS, Tampa and HPP desire to amend the Tampa Agreement to reflect the increased utilization of the HPS Shared Common Facilities by Tampa as a result of the construction of the 2003 Capacity Additions and the purchase of capacity and associated energy from the 2003 Capacity Additions by Tampa;

NOW, THEREFORE, in consideration of the foregoing premises and of the mutual benefits to be obtained from the covenants herein, the Parties hereby agree as follows:

ARTICLE I.

DEFINITIONS

Section 1.1. Additional Definitions – The following additional definitions are hereby added to the Tampa Agreement and all subsection numbering shall be deemed revised accordingly:

"HPS Plant Common Facilities" shall mean facilities including the oil storage and transfer system, the natural gas pipeline system, other than the Natural Gas Pipeline, the well water system, other than the Water Wells and Pumps, the service water systems, the demineralizer, the sewage treatment/wastewater system, the site drainage system, the fire protection system, the control building, office furniture and equipment, exterior lighting, plant communications, warehouse and equipment, miscellaneous equipment and tools, vehicles and access roads, other than the Access Roads, all of which are used or intended to be used exclusively by HPS #1 and #2, but excluding the HPS Site Common Facilities. Capital additions to the HPS Plant Common Facilities made solely by Seminole solely for HPS #3 shall not be part of the HPS Plant Common Facilities and capital additions to the HPS Plant Common Facilities made solely by HPP solely for the 2003 Capacity Additions shall be part of the 2003 Capacity Additions and shall not be part of the HPS Plant Common Facilities.

"HPS Plant Common Facilities Capacity Charge" shall mean the component of the HPS Shared Common Facilities Capacity Charge Adjustment that is the result of Tampa's equitable share of the HPS Plant Common Facilities as a result of the construction of the 2003 Capacity Additions.

"HPS Plant Common Facilities Energy Charge" shall mean the charges to Tampa which are included in the Monthly Energy Charge pursuant to Section 6.5.5 which are the result of Tampa's equitable share of the Fixed Operation and Maintenance Costs and Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities as a result of the construction of the 2003 Capacity Additions.

"HPS Shared Common Facilities" shall mean the HPS Site Common Facilities and the HPS Plant Common Facilities.

"HPS Shared Common Facilities Capacity Charge Adjustment" shall mean the amount by which the Monthly Capacity Charge is adjusted each month pursuant to Section 6.4.9 to reflect the HPS Plant Common Facilities Capacity Charge and the HPS Site Common Facilities Capacity Charge.

"2003 Capacity Additions Actual Availability" shall have the meaning and be calculated in the manner set forth in Appendix BB.

"2003 Capacity Additions Actual Net Electrical Output" shall mean the electrical capability after allowance for station service at which the first phase of the 2003 Capacity Additions can operate as determined pursuant to the 2003 Capacity Additions Performance Tests described in Appendices BB and CC.

"2003 Capacity Additions Actual Net Heat Rate" shall mean the heat rate after allowance for station service at which the first phase of the 2003 Capacity Additions can operate as determined pursuant to the 2003 Capacity Additions Performance Tests described in Appendices BB and CC.

"2003 Capacity Additions Capacity Charge" shall mean the component of the Monthly Capacity Charge as adjusted each month pursuant to Sections 6.4.9 and 6.4.10 that reflects Tampa's purchase of the capacity supplied through the construction of the 2003 Capacity Additions.

"2003 Capacity Additions Capacity Charge Adjustment Effective Date" shall mean the first day of the month following receipt of final approval of the modification of the conditions of certification to allow the construction and operation of the first phase of the 2003 Capacity Additions from the FDEP.

"2003 Capacity Additions Commercial Operation Date" shall mean the date HPP notifies Tampa of the occurrence of the date of Substantial Completion under the 2003 Capacity Additions Construction Contract and the achievement by the CT 2B of minimum net electrical output of eighty (80) megawatts on natural gas adjusted to 59 degrees site conditions, or as otherwise agreed by the Parties.

"2003 Capacity Additions Construction Contract" shall mean the Engineering, Procurement and Construction Agreement between TPS, National Energy Production Corporation and Enron Capital and Trade Resources Corp. dated as of June 17, 1999 relating to the construction of the first phase of the 2003 Capacity Additions.

"2003 Capacity Additions Construction Release" shall mean the date certified at the time in writing by HPP providing authorization to begin construction of the first phase of the 2003 Capacity Additions pursuant to the 2003 Capacity Additions Construction Contract. The date of the 2003 Capacity Additions Construction Release is currently scheduled for November 15, 1999.

"2003 Capacity Additions Contract Year" shall mean a one year period beginning on the first day of the month in which the 2003 Capacity Additions Commercial Operation Date occurs, except that the initial 2003 Capacity Additions Contract Year shall commence on the 2003 Commercial Operation Date and the final 2003 Capacity Additions Contract Year shall end on the date of termination of this Agreement.

"2003 Capacity Additions Correction Period" shall mean the period of time during which HPP continues to pay to Tampa delay damages pursuant to Section 8.3.1.1(a).

"2003 Capacity Additions Energy Charge" shall mean the monthly charges which are included in the Monthly Energy Charge pursuant to Section 6.5.4 which are the result of the Fixed Operation and Maintenance Costs and Variable Operation and Maintenance Costs associated solely with the 2003 Capacity Additions.

"2003 Capacity Additions Energy Charge Effective Date" shall mean the date which is ninety (90) days following the 2003 Capacity Additions Construction Release.

"2003 Capacity Additions Guaranteed Net Electrical Output" shall have the meaning set forth in Appendix BB.

"2003 Capacity Additions Guaranteed Net Heat Rate" shall have the meaning set forth in Appendix BB.

"2003 Capacity Additions Ongoing Guaranteed Availability" shall have the meaning set forth in Section 8.3.3.1(b).

"2003 Capacity Additions Ongoing Guaranteed Net Electrical Output" shall have the meaning set forth in Section 8.3.3.1(a).

"2003 Capacity Additions Ongoing Guaranteed Net Heat Rate" shall have the meaning set forth in Section 8.3.3.1(a).

"2003 Capacity Additions Performance Guarantees" shall have the meaning set forth in Section 8.3.2.

"2003 Capacity Additions Performance Tests" shall mean the performance tests to be performed on the first phase of the 2003 Capacity Additions as set forth in Appendix CC.

Section 1.2. Amended Definitions – The following definitions in the Tampa Agreement shall be amended as set forth below and likewise shall be subject to renumbering as provided in Section 1. 1:

"CT/CC Capacity" shall mean the capacity of the CT/CC Facilities.

"CT/CC Facilities" shall mean the 1993 Non-Coal Facilities.

"Capacity and Corresponding Energy" shall mean the capacity and hourly energy generated by the CT/CC Facilities or the 2003 Capacity Additions, as appropriate given the context.

"Economy Interchange Service" shall mean the sale of interchange service from either the CT/CC Facilities or the 2003 Capacity Additions under terms and

conditions of any service schedule in effect now or in the future, other than Schedules A and B Interchange Service, set forth in a Standard Interchange Agreement.

"Fair Market Value" of any property as of any date shall mean the cash price obtainable in an arm's-length sale between an informed and willing buyer (under no compulsion to buy) and an informed and willing seller (under no compulsion to sell) of the property in question. If the Parties are unable to agree upon a determination of Fair Market Value, such Fair Market Value shall be determined in accordance with the Appraisal Procedure. With respect to determination of Fair Market Value of all or any part of the HPS Shared Common Facilities, such value shall be determined by a third party other than Seminole who is free to use and remove the property without regard to this Agreement.

"Fixed Operation and Maintenance Cost" shall mean the cost associated with the day-to-day staffing of the Hardee Power Station, rents and maintenance of the plant structures, as calculated pursuant to Appendices F, J, V and X.

"HPS Site Common Facilities Capacity Charge" shall mean the component of the HPS Shared Common Facilities Capacity Charge Adjustment that is the result of Seminole's equitable share of the HPS Site Common Facilities as a result of the construction of HPS #3 and Tampa's equitable share of the HPS Site Common Facilities as a result of the construction of the 2003 Capacity Additions.

"Off-System Sales" shall mean Schedules A and B Interchange Service and Economy Interchange Service from the CT/CC Facilities to which Tampa is entitled and the 2003 Capacity Additions.

"Variable Operation and Maintenance Cost" shall mean the cost associated with steam and electricity production and the maintenance of boiler, steam and electric plant, including generation unit start-up costs not otherwise allocated, as calculated pursuant to Appendices G, K, W and Y.

"2003 Capacity Additions" shall mean all or any portion of the following facilities that may be constructed pursuant to the terms of this Agreement: CT 2B, HRSG 2A, HRSG 2B, and ST 2 and, to the extent appropriate in the context, all appurtenant common and supporting facilities owned by HPP at the Site.

Section 1.3 Deleted Definition – The definition of "HPS Site Common Facilities Capacity Charge Adjustment" added by the Third Amendment to the Agreement shall be deleted.

ARTICLE II.

AMENDMENTS REGARDING TERM

Section 2.1 Term of Power Sale – Section 2.2 of the Tampa Agreement shall be amended to read as follows:

> 2.2 Term of Power Sale: HPP shall sell Capacity and Corresponding Energy to Tampa from the CT/CC Facilities and the 2003 Capacity Additions under this Agreement, and Tampa shall purchase such Capacity and Corresponding Energy from HPP, commencing on the Date of Operation with respect to the CT/CC Facilities and commencing on the 2003 Capacity Additions Commercial Operation Date with respect to the 2003 Capacity Additions and continuing thereafter until the termination of this Agreement.

ARTICLE III.

AMENDMENTS REGARDING POWER SUPPLY FACILITIES

Section 3. 1 Description of Facilities – Section 3.1 of the Tampa Agreement shall be amended to read as follows:

> 3.1 Description of Facilities: The Capacity and Corresponding Energy that Tampa shall be entitled to under this Agreement shall only be that from or produced by the CT/CC Facilities and the 2003 Capacity Additions.

ARTICLE IV.

AMENDMENTS REGARDING PURCHASE RIGHTS

Section 4. 1 2003 Capacity Additions Priority – The following Section 4.2 shall be added to the Tampa Agreement:

> 4.2 2003 Capacity Additions Priority: HPP shall cause the Operating Agent to dispatch the 2003 Capacity Additions and corresponding energy solely in accordance with the directions from, and for the benefit of, Tampa.

ARTICLE V.

AMENDMENTS REGARDING OPERATIONS

Section 5.1 Operating Agent. Section 5.1 of the Tampa Agreement shall be amended to read as follows:

> 5.1 Operating Agent: HPP shall select an operating agent (the "Operating Agent"), subject to Tampa's written approval, which approval shall not be unreasonably withheld. The Operating Agent shall operate and maintain HPS #1 and #2, dispatch the CT/CC Capacity and the capacity of the 2003 Capacity Additions, as appropriate given the context, and make Economy Interchange Sales pursuant to a written agreement with HPP (an "Operating Agreement"). The duties of the Operating Agent may be separated and assigned to separate entities, in which case "Operating Agent" shall mean, with respect to any provision in this Agreement, the entity performing the duty indicated by the context of such provision. HPP shall enforce such agreement to cause the Operating Agent to perform its obligations thereunder.

Section 5.2 Dispatch. Section 5.2 of the Tampa Agreement shall be amended to read as follows:

> 5.2 Dispatch: HPP shall cause the Operating Agent to dispatch the CT/CC Capacity and the capacity of the 2003 Capacity Additions, as appropriate given the context, in accordance with instructions from Tampa pursuant to Tampa's rights to purchase energy under this Agreement. HPP may alter the dispatch of the CT/CC Capacity if by so doing it will minimize overall fuel costs to both Seminole and Tampa.

Section 5.3 Delivery. Section 5.3 of the Tampa Agreement shall be amended to read as follows:

> 5.3 Delivery: HPP will deliver the Capacity and Corresponding Energy produced by the CT/CC Facilities and the 2003 Capacity Additions, as appropriate given the context, to Tampa at the Tampa interconnection facilities at the Hardee Power Station illustrated in Appendix A. Transmission of Capacity and Corresponding Energy beyond the Delivery Points shall be the responsibility of Tampa.

Section 5.4 Energy Scheduling. Section 5.4.2 of the Tampa Agreement shall be amended to read as follows:

5.4.2 Energy Scheduling:

(a) Beginning one day prior to the commencement of the sale of power under this Agreement and each day thereafter during its term, Tampa shall contact HPP or its Operating Agent by no later than 11:00 a.m. EPT and provide the amount of Capacity and Corresponding Energy from the CT/CC Capacity that it plans to schedule for the next day. Prior to 1:00 p.m. EPT each day, Tampa shall provide HPP or its Operating Agent with the amount of scheduled capacity and energy it expects to take from the CT/CC Capacity for each clock hour of the next day (a "Daily Schedule"). Such requirements shall take into consideration such operational constraints as may be determined from time to time by the Operating Committee. Prior to 3:00 p.m. EPT each day, HPP or its Operating Agent shall provide Tampa with a schedule of operation for the specific units of the CT/CC Capacity for the next day. Each Party shall make reasonable efforts to minimize departures from the Daily Schedule and shall immediately notify the other Party of any necessary changes.

(b) HPP and Tampa shall coordinate energy scheduling for the 2003 Capacity Additions through the Operating Agent. Tampa shall have the right to dynamically dispatch and place on automatic generation control the 2003 Capacity Additions.

Section 5.5 Energy Scheduling – The following Section 5.4.6 shall be added to the Tampa Agreement:

5.4.6 2003 Capacity Additions: The rights and obligations of the Parties set forth in Sections 5.4.2.1, Section 5.4.4 and 5.4.5 shall apply, as appropriate given the context, to the 2003 Capacity Additions as such additions are placed in service.

Section 5.6 CT/CC Facilities Production Metering – The following Section 5.6.5 shall be added to the Tampa Agreement:

5.6.5 2003 Capacity Additions: The rights and obligations of the Parties set forth in Sections 5.6 through 5.6.4 shall apply, as appropriate given the context, to the 2003 Capacity Additions as such additions are placed in service.

Section 5.7 Inadvertent Transfer of Electric Power and Energy – Section 5.9 of the Tampa Agreement shall be amended to read as follows:

5.9 Inadvertent Transfer of Electric Power and Energy:

(a) HPP, through its Operating Agent, will manage the balance between the cumulative scheduled deliveries and the actual power generated by the CT/CC Facilities.

(b) HPP, through its Operating Agent, will manage the balance between the cumulative scheduled deliveries and the actual power generated by the 2003 Capacity Additions.

Section 5.8 Insurance – Section 5.11.1.2 of the Tampa Agreement shall be amended as set forth in Section 5.8.1 of this Fourth Amendment. In addition, a new Section 5.13 shall be added to the Tampa Agreement as set forth in Section 5.8.2 of this Fourth Amendment to make certain provisions of Section 5.11 of the Tampa Agreement applicable to the 2003 Capacity Additions.

Section 5.8.1 Property Damage Insurance – Section 5.11.1.2 of the Tampa Agreement shall be amended to read as follows:

5.11.1.2 Property Damage Insurance: HPP shall cause to be maintained All Risk Builder's Risk Insurance in an amount equivalent to the completed value of the material and equipment included within the work scope of the 2003 Capacity Additions Construction Contract. This insurance shall insure such material and equipment against all risk of physical loss or damage from any external cause, subject to standard exclusions, and shall be deemed primary insurance for the construction contractor under the 2003 Capacity Additions Construction Contract.

Section 5.8.2 2003 Capacity Additions – The following Section 5.13 shall be added to the Tampa Agreement:

5.13 2003 Capacity Additions: The rights and obligations of the Parties set forth in Section 5.11, Section 5.11.1.1, Sections 5.11.1.3, 5.11.1.5, Section 5.11.2 through 5.11.2.4 and Section 5.12 shall apply, as appropriate given the context, to the 2003 Capacity Additions as such additions are placed in service.

Section 5.9 Appendix A – Appendix A to the Tampa Agreement shall be hereby amended with the replacement Appendix A attached to this Fourth Amendment.

ARTICLE VI.

AMENDMENTS TO CHARGING, BILLING AND PAYMENTS

Section 6.1 Monthly Charge – Section 6.3 of the Tampa Agreement shall be amended to read as follows:

> 6.3 Monthly Charge: Tampa shall pay HPP monthly during the period commencing with the Date of Operation and continuing to and including December 31, 2012 an amount (the "Monthly Charge") equal to the sum of the Monthly Capacity Charge and the Monthly Energy Charge for the CT/CC Facilities (adjusted for Off-System Sales pursuant to Section 6.6 and true-ups pursuant to Section 6.1) and the 2003 Capacity Additions. Effective upon the Date of Operation, Tampa shall pay the Monthly Charge with respect to the CT/CC Facilities in all events, whether or not the CT/CC Facilities generate and deliver the Capacity and Corresponding Energy sold to Tampa hereunder, or whether or not such Facilities are capable of generating and delivering such Capacity and Corresponding Energy, without regard to the cause of any failure or inability to generate and deliver such Capacity and Corresponding Energy, and such payments shall not be subject to any reduction, whether by offset or otherwise. Effective upon the 2003 Capacity Additions Commercial Operation Date, Tampa shall pay the Monthly Charge with respect to the first phase of the 2003 Capacity Additions in all events, whether or not the 2003 Capacity Additions generate and deliver the Capacity and Corresponding Energy sold to Tampa hereunder, or whether or not such 2003 Capacity Additions are capable of generating and delivering such Capacity and Corresponding Energy, without regard to the cause of any failure or inability to generate and deliver such Capacity and Corresponding Energy, and such payments shall not be subject to any reduction, whether by offset or otherwise. To the extent that no energy is generated and the calculation of any component of the Monthly Charge requires an allocation of expenses, such expenses shall be allocated as provided for in this Article VI.

Section 6.2 Monthly Capacity Charge – Section 6.4 of the Tampa Agreement shall be amended to read as follows:

> 6.4 Monthly Capacity Charge: The Monthly Capacity Charge shall be equal to the sum of the Monthly CT/CC Capacity Charge and the 2003 Capacity Additions Capacity Charge. For the Monthly CT/CC Capacity Charge, during the period from the Date of Operation to the earlier of (a) the last day of the tenth Contract Year and (b) December 31, 2003, the Monthly CT/CC Capacity Charge shall be $1,137,250. During the period from the end of the period described in the preceding sentence through the remaining term of this Agreement, the Monthly CT/CC Capacity Charge shall be $1,184,917. For the

2003 Capacity Additions Capacity Charge, during the period from the 2003 Capacity Additions Commercial Operation Date until December 31, 2012, the 2003 Capacity Additions Capacity Charge for the first phase shall be $451,550. To the extent that the 2003 Capacity Additions Commercial Operation Date occurs during the month, the 2003 Capacity Additions Capacity Charge for such month shall be the 2003 Capacity Additions Capacity Charge set forth above multiplied by a fraction, the numerator of which is the number of days of the month starting with and subsequent to the 2003 Capacity Additions Commercial Operation Date and the denominator of which is the total number of days in the month in which the 2003 Capacity Additions Commercial Operation Date occurs. The Monthly Capacity Charge described in this Section 6.4 shall be subject to adjustment only as expressly provided for in this Agreement.

Section 6.3 HPS Shared Common Facilities Capacity Charge. – Section 6.4.9 of the Tampa Agreement shall be amended to read as follows:

6.4.9 HPS Shared Common Facilities Capacity Charge Adjustment:

(a) Commencing on the HPS #3 Capacity Charge Adjustment Effective Date and subject to Sections 6.4.9.1 through 6.4.9.4, the HPS Shared Common Facilities Capacity Charge Adjustment shall be a credit of $19,494 to reflect the utilization of the HPS Site Common Facilities by HPS #3.

(b) Commencing on the 2003 Capacity Additions Capacity Charge Adjustment Effective Date and subject to Sections 6.4.9.1 through 6.4.9.4, the HPS Shared Common Facilities Capacity Charge Adjustment shall be a charge of $57,710 to reflect the utilization of the HPS Site Common Facilities by HPS #3 and the 2003 Capacity Additions and the utilization of the HPS Plant Common Facilities by the 2003 Capacity Additions.

(c) Commencing on January 1, 2003 and subject to Sections 6.4.9.1 through 6.4.9.4, the HPS Shared Common Facilities Capacity Charge Adjustment shall be a charge of $60,154 to reflect the utilization of the HPS Site Common Facilities by HPS #3 and the 2003 Capacity Additions and the utilization of the HPS Plant Common Facilities by the 2003 Capacity Additions.

(d) The HPS Shared Common Facilities Capacity Charge Adjustment, as set forth in Section 6.4.9(a) through (c), is calculated on the assumptions that (i) the HPS #3 Capacity Charge Adjustment Effective Date shall precede the 2003 Capacity Additions Capacity Charge Adjustment Effective Date and (ii) the HPS #3 Capacity Charge Adjustment Effective Date and the 2003 Capacity Additions Capacity Charge Adjustment Effective Date shall occur prior to January 1, 2003. In the event that the sequencing of such effective dates shall occur other than as assumed above, the HPS Shared Common Facilities Capacity Charge Adjustment,

as set forth in Section 6.4.9(a) through (c), shall be recalculated to reflect the changes in the sequencing of such effective dates and no other changes.

6.4.9.1 Termination of Use of HPS Shared Common Facilities: At such time, if any, that either Seminole or Tampa permanently ceases to use all or any part of the HPS Shared Common Facilities, the HPS Shared Common Facilities Capacity Charge Adjustment shall be equitably adjusted to reflect such reduced usage. The Parties shall promptly prepare and execute the necessary amendments to this Agreement and HPP shall file such amendments with the FERC as are required. The adjustment of the HPS Shared Common Facilities Capacity Charge Adjustment with respect to HPS #3 or the 2003 Capacity Additions shall be effective on the later of the first day of the month following written notice by HPP to Tampa that Seminole is permanently ceasing the use of such facilities for HPS #3 or that HPP is permanently ceasing the use of such facilities for the 2003 Capacity Additions or the day on which the FERC has permitted such adjustment to go into effect.

6.4.9.2 Cancellation of HPS #3 or the 2003 Capacity Additions: If either HPS #3 or the 2003 Capacity Additions is or are canceled following the HPS #3 Capacity Charge Adjustment Effective Date or the 2003 Capacity Additions Capacity Charge Adjustment Effective Date, as appropriate given the context, the HPS Shared Common Facilities Capacity Charge Adjustment shall be adjusted accordingly. The adjustment of the HPS Shared Common Facilities Capacity Charge Adjustment with respect to HPS #3 shall be effective on the later of the first day of the month following written notice by HPP to Tampa that HPS #3 has been canceled or the day on which the FERC has permitted such adjustment to go into effect. The adjustment of the HPS Shared Common Facilities Capacity Charge Adjustment with respect to 2003 Capacity Additions shall be effective on the later of the first day of the month following written notice by HPP to Tampa that the 2003 Capacity Additions have been canceled or the day on which the FERC has permitted such adjustment to go into effect. For purposes of this Section 6.4.9.2 and Section 6.5.3, HPS #3 shall be deemed "canceled" as the result of any action that cancels its construction altogether or delays the scheduled HPS #3 Commercial Operation Date by six (6) or more years beyond January 1, 2002. For purposes of this Section 6.4.9.2, Section 6.5.4 and Section 6.5.5, the 2003 Capacity Additions shall be deemed "canceled" as the result of any action that cancels construction altogether or delays the scheduled 2003 Capacity Additions Commercial Operation Date by six (6) or more years beyond May 15, 2000.

6.4.9.3. Delay of HPS #3 or the 2003 Capacity Additions: Should either the HPS #3 Construction Release or the HPS #3 Commercial Operation Date be delayed for a period that results in a delay of the scheduled HPS #3 Commercial Operation Date by more than one (1) year but less than six (6) years from January 1, 2002, then the HPS Shared Common Facilities Capacity Charge Adjustment with respect to HPS #3 shall be recalculated pursuant to Section 6.4.9(d) for the period equal to the scheduled delay. Such recalculation of the

HPS Shared Common Facilities Capacity Charge Adjustment shall be effective on the later of the first day of the month following written notice by HPP to Tampa that HPS #3 has been delayed or the day on which the FERC has permitted such suspension to go into effect. Should either the 2003 Capacity Additions Construction Release or the 2003 Capacity Additions Commercial Operation Date be delayed for a period that results in a delay of the scheduled 2003 Capacity Additions Commercial Operation Date by more than one (1) year but less than six (6) years from May 15, 2000, then the HPS Shared Common Facilities Capacity Charge Adjustment with respect to the 2003 Capacity Additions shall be recalculated pursuant to Section 6.4.9(d) for the period equal to the scheduled delay. Such recalculation of the HPS Shared Common Facilities Capacity Charge Adjustment shall be effective on the later of the first day of the month following written notice by HPP to Tampa that the 2003 Capacity Additions have been delayed or the day on which the FERC has permitted such suspension to go into effect.

6.4.9.4 Future Adjustments of HPS #3 or the 2003 Capacity Additions: If either HPS #3 or the 2003 Capacity Additions are reconfigured or adjusted in their nominal electrical capacity capability and/or in their use of the HPS Shared Common Facilities, the HPS Shared Common Facilities Capacity Charge Adjustment shall be equitably adjusted and HPP shall promptly file any necessary documents with the FERC to carry out the intent of the Parties under this Section.

Section 6.4 Further Adjustments to 2003 Capacity Additions Capacity Charge: The following Section 6.4.10 shall be added to the Tampa Agreement:

6.4.10 Further Adjustments to 2003 Capacity Additions Capacity Charge: As of the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Capacity Charge shall be subject to adjustment as provided for in Sections 6.4.2 through 6.4.8, provided, however, that Tampa shall be entitled to one hundred percent (100%) of the reduction provided for in Section 6.4.7 and shall be responsible for one hundred percent (100%) of the cost increase provided for in Section 6.4.8. Upon notification by Tampa to HPP to complete construction of the second phase of the 2003 Capacity Additions pursuant to Section 10.2.1, the Parties shall make further adjustments to the 2003 Capacity Additions Capacity Charge and HPP shall promptly file any necessary documents with the FERC to carry out the intent of the Parties under this Section.

Section 6.5 Monthly Energy Charge – Certain parts of Section 6.5 of the Tampa Agreement and Appendices F, G, H, J, K, L, U, X and Y to the Tampa Agreement shall be amended to reflect changes in the Monthly Energy Charge. In addition, Sections 6.5.4 and 6.5.5 and Appendices V, W, Z and AA shall be added to the Tampa Agreement.

Section 6.5.1 Monthly Energy Charge – Section 6.5 of the Tampa Agreement shall be amended to read as follows:

> 6.5. Monthly Energy Charge: The Monthly Energy Charge shall be comprised of (i) the Monthly Combustion Turbine Cost, (ii) the Monthly Combined Cycle Cost, (iii) the HPS Site Common Facilities Energy Charge, (iv) the 2003 Capacity Additions Energy Charge and (v) the HPS Plant Common Facilities Energy Charge. Costs and allocations of costs shall be determined in accordance with the records and accounting system of HPP. Such records and accounting system will be kept according to generally accepted utility accounting practices, including the FERC Uniform System of Accounts.

Section 6.5.2 Monthly Combustion Turbine Cost – Section 6.5.1 of the Tampa Agreement shall be amended to read as follows:

> 6.5.1 Monthly Combustion Turbine Cost: During any period when any of the CT units is operated as a stand-alone combustion turbine, the Monthly Combustion Turbine Cost shall be the sum of:
>
> (a) The Tampa portion of the cost of fuel consumed by any CT unit other than the CT 2B as part of the 2003 Capacity Additions during the Delivery Month, including transportation and handling costs, allocated to Tampa on an hourly basis according to type of fuel, fuel cost, hourly unit load, the demonstrated heat rate corresponding to average load level in each hour and Tampa's proportion of the hourly load. (See Appendix E). In addition, a monthly adjustment shall be added to the total of the hourly charges to compensate for off-line fuel consumption and variations in unit heat rate. Such adjustment shall be calculated by subtracting from the total actual fuel consumption for the 1993 Non-Coal Facilities for each month the Theoretical Total Fuel Consumption. The "Theoretical Total Fuel Consumption" shall be defined as the product of the hourly average loadings and the corresponding heat rates. The Tampa portion of such adjustment shall be determined by dividing the total MWh delivered to Tampa from such CT unit during the Delivery Month by the total MWh generated by such CT unit during the Delivery Month; and
>
> (b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to any CT unit other than the CT 2B as part of the 2003 Capacity Additions as calculated pursuant to Appendix F; and (ii) the Tampa portion of the Delivery Month Variable Operation and

Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to any CT unit other than the CT 2B as part of the 2003 Capacity Additions as calculated pursuant to Appendix G less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by any CT unit other than the CT 2B as part of the 2003 Capacity Additions for Tampa during the previous twelve (12) month period ending with the Delivery Month bears to the total net energy generated by such unit during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales);

(c) Forty percent (40%) of the Delivery Month fixed charges for replaced property units of the CT 2A, as calculated pursuant to Appendix T; and

(d) Forty percent (40%) of the Delivery Month administrative and general expenses allocated to any CT unit, as calculated pursuant to Appendix H, until the occurrence of the 2003 Capacity Additions Energy Charge Effective Date at which time the percentage shall be fifty nine and seventy-seven one hundredths percent (59.77%) of the Delivery Month administrative and general expenses allocated to any CT unit, as calculated pursuant to Appendix H.

Section 6.5.3 Monthly Combined Cycle Cost – Section 6.5.2 of the Tampa Agreement shall be amended to read as follows:

6.5.2 Monthly Combined Cycle Cost: The Monthly Combined Cycle Cost shall be the sum of:

(a) The Tampa portion of the cost of fuel consumed by the CC 1 during the Delivery Month, including transportation and handling costs, allocated to Tampa on an hourly basis according to type of fuel, fuel cost, hourly unit load, the demonstrated heat rate corresponding to average load level in each hour and Tampa's proportion of the hourly load. (See Appendix I). In addition, a monthly adjustment shall be added to the total of the hourly charges to compensate for off-line fuel consumption and variations in unit heat rate. Such adjustment shall be calculated by subtracting from the total actual fuel consumption for the 1993 Non-Coal Facilities for each month the Theoretical Total Fuel Consumption. The "Theoretical Total Fuel Consumption" shall be defined as the product of the hourly average loadings and the corresponding heat rates. The Tampa portion of such adjustment shall be determined by dividing the total MWh delivered to Tampa from the CC 1 during the Delivery Month by the total MWh generated by the CC 1 during the Delivery Month; and

(b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to the CC 1 as calculated pursuant to Appendix J; and (ii) the Tampa portion of the Delivery Month Variable Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) associated with the CC 1 as calculated pursuant to Appendix K less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by the CC 1 for Tampa during the previous twelve (12) month period ending with the Delivery Month bears to the total net energy generated by the CC 1 during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales); and

(c) Forty percent (40%) of the Delivery Month fixed charges for replaced property units of the CC 1, as calculated pursuant to Appendix U; and

(d) Forty percent (40%) of the Delivery Month administrative and general expenses allocated to the Combined Cycle Units, as calculated pursuant to Appendix L, until the occurrence of the 2003 Capacity Additions Energy Charge Effective Date at which time the percentage shall be fifty nine and seventy-seven one hundredths percent (59.77%) of the Delivery Month administrative and general expenses allocated to the Combined Cycle Units, as calculated pursuant to Appendix L.

Section 6.5.4 HPS Site Common Facilities Energy Charge – Section 6.5.3 of the Tampa Agreement shall be amended to read as follows:

6.5.3 HPS Site Common Facilities Energy Charge:

(a) The HPS Site Common Facilities Energy Charge shall commence on the earlier of the HPS #3 Energy Charge Effective Date or the 2003 Capacity Additions Energy Charge Effective Date and shall continue through the remaining term of this Agreement. The HPS Site Common Facilities Energy Charge shall be calculated pursuant to Appendices X and Y and shall be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4. The allocations in Appendix X are calculated on the assumption that the 2003 Capacity Additions Energy Charge

Effective Date precedes the HPS #3 Energy Charge Effective Date. In the event that the sequencing of such effective dates shall occur other than as assumed, the allocations shall be recalculated to reflect the changes in sequencing of such effective dates and no other changes.

(b) Commencing on the HPS #3 Energy Charge Effective Date, the HPS Site Common Facilities Energy Charge to Tampa shall include an allocation to reflect Seminole's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities for HPS #3, as calculated pursuant to Appendices X and Y.

(c) Commencing on the 2003 Capacity Additions Energy Charge Effective Date, the HPS Site Common Facilities Energy Charge to Tampa shall include an allocation to reflect Tampa's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities for the 2003 Capacity Additions, as calculated pursuant to Appendices X and Y.

Section 6.5.5 2003 Capacity Additions Site Common Facilities Energy Charge – The following Section 6.5.4 shall be added to the Tampa Agreement:

6.5.4 2003 Capacity Additions Energy Charge: The 2003 Capacity Additions Energy Charge shall commence on the 2003 Capacity Additions Commercial Operation Date and shall continue through the remaining term of this Agreement. The 2003 Capacity Additions Energy Charge to Tampa shall be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4. The 2003 Capacity Additions Energy Charge shall be the sum of:

(a) The total cost of fuel consumed by the 2003 Capacity Additions during the Delivery Month, including transportation and handling costs; and

(b) The Delivery Month Fixed Operation and Maintenance Costs and Delivery Month Variable Operation and Maintenance Costs (but excluding the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the HPS Shared Common Facilities) allocated to the 2003 Capacity Additions as calculated pursuant to Appendix Z; and

(c) The Delivery Month fixed charges for replaced property units of the 2003 Capacity Additions, as calculated pursuant to Appendix AA.

Section 6.5.6 HPS Plant Common Facilities Energy Charge – The following Section 6.5.5 shall be added to the Tampa Agreement:

6.5.5 HPS Plant Common Facilities Energy Charge: The HPS Plant Common Facilities Energy Charge shall commence on the 2003 Capacity Additions Energy Charge Effective Date and shall continue through the remaining term of this Agreement. The HPS Plant Common Facilities Energy Charge to Tampa shall include an amount to reflect Tampa's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Plant Common Facilities as a result of the construction by HPP of all or part of the 2003 Capacity Additions as calculated pursuant to Appendices V and W. The HPS Plant Common Facilities Energy Charge shall also be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4.

Section 6.6 Interchange Sales – Section 6.6 of the Tampa Agreement shall be amended to read as follows:

6.6 Interchange Sales: Except as provided for in Section 6.6.4, Tampa shall be entitled to forty percent (40%) of the Benefits Derived from all Off-System Sales of Capacity and Corresponding Energy. Sales and payments for or recovery of the attributable costs and benefits shall be made in the following manner.

Section 6.7 Interchange Sales from the 2003 Capacity Additions – The following Section 6.6.4 shall be added to the Tampa Agreement:

6.6.4 Interchange Sales from the 2003 Capacity Additions: Notwithstanding the foregoing, Tampa shall be entitled to one hundred (100%) of the Benefits Derived from all Off-System Sales of Capacity and Corresponding Energy made from the 2003 Capacity Additions.

Section 6.8 Test Fuel – Section 6.7.1 of the Tampa Agreement shall be amended to read as follows:

6.7.1 Test Fuel: Tampa shall pay HPP forty percent (40%) of the cost of all fuel use associated with Test Operation of the 1993 Non-Coal Facilities and one hundred percent (100%) of the cost of all fuel use associated with the activities in connection with the check-out, testing and start-up of the 2003 Capacity Additions, including transportation and handling cost.

Section 6.9 Test Energy from 2003 Capacity Additions – The following Section 6.7.3 shall be added to the Tampa Agreement:

6.7.3 Test Energy from 2003 Capacity Additions: Tampa shall purchase any energy produced by the 2003 Capacity Additions during test

operation. If, after reasonable efforts, Tampa is unable to purchase such energy as reasonably necessary to allow test operation, HPP shall cause the Operating Agent to sell any such energy. HPP shall pay Tampa one hundred percent (100%) of all revenues from such sales from the 2003 Capacity Additions. Such payment shall be in the form of a credit to Tampa's liability for fuel cost pursuant to this Section 6.7.

ARTICLE VII.

AMENDMENTS TO DESIGN, CONSTRUCTION AND LICENSING

Section 7.1 Section 7.1 of the Tampa Agreement shall be amended to read as follows:

7.1 Design Review by Tampa: HPP will provide Tampa copies of plot plans, equipment arrangement drawings, piping and instrumentation drawings, station one-line drawings, electrical elementary drawings, equipment specifications and all environmental permit applications related to the CT/CC Facilities and the 2003 Capacity Additions for review within forty-eight (48) hours of the time it receives such items from the contractor or completes such documents for which it is responsible. Tampa may review and provide comments to HPP regarding such technical documentation and applications. Tampa's review and comments will be of an advisory nature. To the extent practicable, Tampa will be provided four (4) working days to review each document transmittal. Tampa may at its option attend regularly scheduled design review and project status meetings that are held by HPP and the contractor.

Section 7.2 Construction Review by Tampa: Section 7.2 of the Tampa Agreement shall be amended to read as follows:

Section 7.2 Construction Review by Tampa: Tampa will have the right to maintain a construction representative on the Site during construction of the CT/CC Facilities and the 2003 Capacity Additions, provided such activity does not interfere with the work. The role of the construction representative will be to monitor on-site activities for Tampa. The construction representative will have access to all construction areas and activities, including drawings and other technical documentation. Upon request, HPP will provide the construction representative with copies of available schedules and drawings and technical documents. HPP will permit the construction representative to attend, if he so elects, regularly scheduled construction progress and coordination meetings. Tampa will provide construction office space for the construction representative. HPP will, at no cost to Tampa, provide convenient space for a construction office and nearby parking for the construction representative. The construction representative will observe all legal, job site safety, security and construction rules established for the project construction. From time to time, other Tampa representatives and agents may visit the Site to review progress and attend

appropriate meetings related to construction of the CT/CC Facilities and the 2003 Capacity Additions. HPP will provide a construction progress report to Tampa on a monthly basis describing the status of all major project equipment deliveries, major construction activities, and testing activities. Upon receipt from the contractor, HPP will provide Tampa one set of the as-built plant design drawings and one set of equipment manuals.

ARTICLE VIII.

AMENDMENTS TO PERFORMANCE REPRESENTATIONS

Section 8.1 Performance Representation – Section 8.1 of the Tampa Agreement shall be amended to read as follows:

8.1 Performance Representation: HPP shall construct or cause to be constructed the 1993 Non-Coal Facilities and the 2003 Capacity Additions, to the extent such additions are constructed pursuant to Section 10.2.1, and shall operate or cause to be operated the 1993 Non-Coal Facilities and the 2003 Capacity Additions in accordance with Prudent Utility Practice.

Section 8.2 2003 Capacity Additions Guarantees – The following Section 8.3 shall be added to the Tampa Agreement:

8.3 2003 Capacity Additions:

8.3.1 In-Service Date Guarantee: HPP guarantees that the 2003 Capacity Additions Commercial Operation Date shall occur on or before May 15, 2000, as the same may be extended pursuant to this Agreement due to Force Majeure.

8.3.1.1 Liquidated Damages to the Account of HPP: In the event that the 2003 Capacity Additions Commercial Operation Date is delayed beyond May 15, 2000, then HPP shall pay Tampa as liquidated damages and not as penalty, the following amounts under the following conditions:

(a) Delay in Completion: If, by May 15, 2000, the 2003 Capacity Additions Commercial Operations Date has not occurred, HPP shall pay to Tampa the sum of $9,000 for each day elapsed beyond May 15, 2000, until August 14, 2000. If, by August 15, 2000, the 2003 Capacity Additions Commercial Operation Date has not occurred, HPP shall continue to pay Tampa $7,000 per day until November 14, 2000. After November 14, 2000 or if HPP is no longer receiving or entitled to receive daily delay damages under the 2003 Capacity Additions Construction Contract, HPP may at its option pay Tampa $8,000 for each succeeding day up to May 15, 2002. Upon HPP's termination of the

payment of delay damages prior to the 2003 Capacity Additions Commercial Operation Date, Tampa may, upon thirty (30) days written notice to HPP, purchase the property and rights of the 2003 Capacity Additions described in Section 11.3 in accordance with the provisions of such section. In all events, such purchase by Tampa shall be subject to compliance by HPP and/or Tampa, as applicable, with all applicable conditions contained in any financing documents relating to the 2003 Capacity Additions.

(b) Payments for Delay: Payments required by this Section 8.3.1.1 shall be paid monthly by the 15th day of the following month. All payments to Tampa shall be by wire or electronic funds transfer to Tampa's account in a domestic bank as directed in writing by Tampa.

(c) Liquidation of Remedies: Except as provided for in Section 8.3.1.1(a), the liquidated damages provided herein shall be in lieu of and shall, when paid or credited, relieve HPP from all liability for any and all extra costs, losses or expenses, claims and penalties, loss of use of the first phase of the 2003 Capacity Additions, cost of capital, loss of revenue, and any other damages of whatsoever nature incurred by Tampa which are occasioned by any such delay in the 2003 Capacity Additions Commercial Operation Date.

8.3.2 Initial Performance Guarantees: The 2003 Capacity Additions Performance Guarantees shall mean the performance characteristics of the first phase of the 2003 Capacity Additions as set forth in Appendix BB, which HPP guarantees the first phase of the 2003 Capacity Additions will simultaneously achieve when tested pursuant to the 2003 Capacity Additions Performance Tests, while complying with all applicable environmental requirements.

8.3.2.1 Remedial Procedure: If the 2003 Capacity Additions Performance Guarantees have not been met on or prior to May 15, 2000, HPP shall take corrective action throughout the 2003 Capacity Additions Correction Period, provided that if the 2003 Capacity Additions Commercial Operation Date occurs before the end of the 2003 Capacity Additions Correction Period, the 2003 Capacity Additions Correction Period shall continue until the earlier of the date two (2) years following the 2003 Capacity Additions Commercial Operation Date and the date on which the 2003 Capacity Additions Performance Guarantees are achieved. The 2003 Capacity Additions Capacity Charge during the 2003 Capacity Additions Correction Period, if any, shall be determined in accordance with this and other provisions of this Fourth Amendment. If, on the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Performance Guarantees have not been met, Tampa shall, for each applicable month, be entitled to an adjustment to the 2003 Capacity Additions Capacity Charge in accordance with Section 8.3.2.2, such adjustment shall be Tampa's sole remedy for any failure to fulfill the 2003 Capacity Additions Performance Guarantees and such failure shall not be an Event of Default under this Agreement. From time to time after the first adjustment described above until the end of the 2003 Capacity Additions Correction Period, HPP may at its option

conduct additional 2003 Capacity Addition Performance Tests on the first phase of the 2003 Capacity Additions and recalculate the adjustment of the 2003 Capacity Additions Capacity Charge in accordance with the most recent such tests and Section 8.3.2.2.

8.3.2.2 Capacity Charge Adjustment: The Parties agree that as specified in Section 8.3.2.1, if the 2003 Capacity Additions Performance Guarantees have not been met on the 2003 Capacity Additions Commercial Operation Date, HPP shall adjust the 2003 Capacity Additions Capacity Charge to Tampa as noted in Items (a), (b) and (c) of this Section for each applicable month. Any decreases in the 2003 Capacity Additions Capacity Charge as a result of this Section shall be considered liquidated damages and not penalty sums. The initial adjustments of the 2003 Capacity Additions Capacity Charge shall take place on 2003 Capacity Additions Commercial Operation Date and all adjustments shall be based upon the difference between the actual performance of the first phase of the 2003 Capacity Additions, as determined by the 2003 Capacity Additions Performance Tests, and the 2003 Capacity Additions Performance Guarantees for the following specific items:

(a) 2003 Capacity Additions Net Electrical Output: If the 2003 Capacity Additions Actual Net Electrical Output is less than the 2003 Capacity Additions Guaranteed Net Electrical Output, then HPP shall reduce the 2003 Capacity Additions Capacity Charge by two percent (2%) for each percentage point, with portions of a percentage point prorated, that the 2003 Capacity Additions Actual Net Electrical Output capability is less than the 2003 Capacity Additions Guaranteed Net Electrical Output.

(b) 2003 Capacity Additions Net Heat Rate: If the 2003 Capacity Additions Actual Net Heat Rate is less than the 2003 Capacity Additions Guaranteed Net Heat Rate, then HPP shall reduce the 2003 Capacity Additions Capacity Charge by one and one tenth percent (1.1%) for each percentage point, with portions of a percentage point prorated, that the 2003 Capacity Additions Actual Net Heat Rate is less than the 2003 Capacity Additions Guaranteed Net Heat Rate.

(c) Limitations of Adjustments: The adjustment of the 2003 Capacity Additions Capacity Charge for differences between the 2003 Capacity Additions Actual Net Electrical Output and the 2003 Capacity Additions Actual Net Heat Rate and the 2003 Capacity Additions Guaranteed Net Electrical Output and the 2003 Capacity Additions Guaranteed Net Heat Rate, respectively, shall not, in the aggregate, exceed thirty three percent (33%) of the 2003 Capacity Additions Capacity Charge.

8.3.3. 2003 Capacity Additions Ongoing Performance Guarantees: If, after the beginning of the first full 2003 Capacity Additions Contract Year after the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Ongoing Performance Guarantees, as defined in Section 8.3.3.1 below,

have not been met, as determined by an Annual 2003 Capacity Additions Performance Test or any Optional 2003 Capacity Additions Performance Test or a 2003 Capacity Additions Retest, as provided in Section 8.3.3.2 below, HPP shall adjust the 2003 Capacity Additions Capacity Charge to Tampa as provided in Section 8.3.3.4 below.

8.3.3.1. Performance Criteria: "2003 Capacity Additions Ongoing Performance Guarantees" shall mean the performance characteristics of the 2003 Capacity Additions as applicable for a particular 2003 Capacity Additions Contract Year, which HPP guarantees the 2003 Capacity Additions (i) will simultaneously achieve, with respect to (a) below, when tested in accordance with the 2003 Capacity Additions Performance Tests conducted pursuant to Section 8.3.3.2, while complying with all applicable environmental requirements and (ii) will have achieved, with respect to (b) below, on a historical basis.

(a) 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output and Heat Rate: The 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate shall be determined in the following manner:

(i) during the period from the 2003 Capacity Additions Commercial Operation Date to the end of the first full 2003 Capacity Additions Contract Year after the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output shall be equal to the lesser of the 2003 Capacity Additions Actual Net Electrical Output determined in the 2003 Capacity Additions Performance Test upon which the declaration of the 2003 Capacity Additions Commercial Operation Date was based and the 2003 Capacity Additions Guaranteed Net Electrical Output, and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate shall be equal to the greater of the 2003 Capacity Additions Actual Net Heat Rate determined in such 2003 Capacity Additions Performance Test and the 2003 Capacity Additions Guaranteed Net Heat Rate;

(ii) during the second full 2003 Capacity Additions Contract Year after the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output shall be equal to the average of the 2003 Capacity Additions Actual Net Electrical Output determined in the Annual 2003 Capacity Additions Performance Test in the previous 2003 Capacity Additions Contract Year and the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output during the previous 2003 Capacity Additions Contract Year; and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate during a 2003 Capacity Additions Contract Year shall be the average of the 2003 Capacity Additions Actual Net Heat Rate determined in the Annual 2003 Capacity Additions Performance Test in the previous 2003 Capacity Additions Contract Year and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate during the previous 2003 Capacity Additions Contract Year;

(iii) during each succeeding 2003 Capacity Additions Contract Year, the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate for such 2003 Capacity Additions Contract Year shall be the average of the 2003 Capacity Additions Actual Net Electrical Output and of the 2003 Capacity Additions Actual Net Heat Rate, respectively, determined in the Annual 2003 Capacity Additions Performance Test in each of the two preceding 2003 Capacity Additions Contract Years; provided

(iv) the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output shall not be less than eighty percent (80%) of, and the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate shall not be greater than one hundred twenty percent (120%) of, the 2003 Capacity Additions Actual Net Electrical Output and the 2003 Capacity Additions Actual Net Heat Rate, respectively, determined in the 2003 Capacity Additions Performance Test upon which the declaration of the 2003 Capacity Additions Commercial Operation Date was based; and further provided

(v) the values used to determine the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output pursuant to clauses (ii) and (iii) shall not be greater than the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output determined pursuant to clause (i).

(b) 2003 Capacity Additions Ongoing Guaranteed Availability: The 2003 Capacity Additions Ongoing Guaranteed Availability shall be determined in the following manner:

(i) during the period from the 2003 Capacity Additions Commercial Operation Date to the end of the first full 2003 Capacity Additions Contract Year after the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Ongoing Guaranteed Availability shall be eighty five percent (85%);

(ii) during the second full 2003 Capacity Additions Contract Year, after the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Ongoing Guaranteed Availability shall be equal to the average of ninety percent (90%) and the 2003 Capacity Additions Actual Availability during the previous 2003 Capacity Additions Contract Year;

(iii) during each succeeding 2003 Capacity Additions Contract Year, the 2003 Capacity Additions Ongoing Guaranteed Availability for such 2003 Capacity Additions Contract Year shall be equal to the average 2003 Capacity Additions Actual Availability during the previous two 2003 Capacity Additions Contract Years; provided that

(iv) the 2003 Capacity Additions Ongoing Guaranteed Availability shall not be less than the average availability of equipment similar to

the 2003 Capacity Additions as then reported in the North American Electric Reliability Council Generator Availability Data System.

8.3.3.2. 2003 Capacity Additions Performance Tests: HPP shall conduct an annual 2003 Capacity Additions Performance Test within sixty (60) days prior to the beginning of each 2003 Capacity Additions Contract Year (the "Annual 2003 Capacity Additions Performance Test"). In addition, Tampa shall have the option, upon thirty (30) days prior notice to HPP, to require one additional 2003 Capacity Additions Performance Test at any time during the 2003 Capacity Additions Contract Year (an "Optional 2003 Capacity Additions Performance Test"). The 2003 Capacity Additions Capacity Charge shall be adjusted, based upon the results of any such Annual 2003 Capacity Additions Performance Test unless and until an Optional 2003 Capacity Additions Performance Test is conducted. If an Optional 2003 Capacity Additions Performance Test is conducted, the 2003 Capacity Additions Capacity Charge shall be adjusted based on such Optional 2003 Capacity Additions Performance Test. Notwithstanding the preceding two sentences, if, at HPP's option, another 2003 Capacity Additions Performance Test (a "2003 Capacity Additions Retest") is conducted within thirty (30) days of such Annual or Optional 2003 Capacity Additions Performance Test, the 2003 Capacity Additions Capacity Charge shall not be adjusted until such Retest is conducted. In the case of a 2003 Capacity Additions Retest, the 2003 Capacity Additions Capacity Charge shall be adjusted based on the results of the 2003 Capacity Additions Retest and the immediately preceding 2003 Capacity Additions Performance Test, whichever would result in the higher 2003 Capacity Additions Capacity Charge. Thereafter, HPP may request an additional 2003 Capacity Additions Retest at any time upon thirty (30) days prior written notice to Tampa and the 2003 Capacity Additions Capacity Charge shall thereafter be adjusted based on the results of the 2003 Capacity Additions Retest and the 2003 Capacity Additions Performance Test performed immediately prior to such Retest, whichever would result in the higher 2003 Capacity Additions Capacity Charge.

8.3.3.3. Normalization of Tests and Data: Calculation of electrical capacity, heat rate and availability of the 2003 Capacity Additions for purposes of the 2003 Capacity Additions Ongoing Performance Guarantees shall conform with the following:

(a) 2003 Capacity Additions Performance Tests: 2003 Capacity Additions Performance Tests shall be conducted in accordance with Prudent Utility Practice and the results of all 2003 Capacity Additions Performance Tests shall be corrected according to Appendix CC.

(b) Availability: Determinations of availability shall be adjusted to compensate for outages and degradations of performance due to Force Majeure or to failure of equipment that causes a continuous unit outage of more than thirty (30) days for reasons other than gross negligence or willful misconduct of HPP or the Operating Agent.

8.3.3.4. Calculation of Adjustment: Any such adjustments of the 2003 Capacity Additions Capacity Charge shall take effect as of the Delivery Month next following the month in which a 2003 Capacity Additions Performance Test is performed on which such adjustment is based; provided that, effective with the first Delivery Month of each successive 2003 Capacity Additions Contract Year, adjustments shall be recalculated based on the previously applicable 2003 Capacity Additions Performance Test results, as applied to the 2003 Capacity Additions Ongoing Performance Guarantees in effect for such new 2003 Capacity Additions Contract Year. All adjustments shall be based upon the difference between the actual performance of the 2003 Capacity Additions and the 2003 Capacity Additions Ongoing Performance Guarantees, as determined by the testing procedures set forth in Section 8.3.3.2 above, for the following specific items:

(a) 2003 Capacity Additions Net Electrical Output: If the 2003 Capacity Additions Actual Net Electrical Output is less than the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output, HPP shall reduce the 2003 Capacity Additions Capacity Charge by two tenths of one percent (.2%) for each percentage point, with portions of a percentage point prorated, that the 2003 Capacity Additions Actual Net Electrical Output is less than the 2003 Capacity Additions Ongoing Guaranteed Net Electrical Output.

(b) 2003 Capacity Additions Net Heat Rate: If the 2003 Capacity Additions Actual Net Heat Rate differs from the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate, then HPP shall adjust the 2003 Capacity Additions Capacity Charge by two tenths of one percent (.2%) for each percentage point, with portions of a percentage point prorated, that the 2003 Capacity Additions Actual Net Heat Rate differs from the 2003 Capacity Additions Ongoing Guaranteed Net Heat Rate.

(c) 2003 Capacity Additions Availability: If the 2003 Capacity Additions Actual Availability during the previous 2003 Capacity Additions Contract Year was less than the 2003 Capacity Additions Ongoing Guaranteed Availability during such 2003 Capacity Additions Contract Year, then HPP shall reduce the 2003 Capacity Additions Capacity Charge by two tenths of one percent (0.2%) for each percentage point, with portions of a percentage point prorated, that the 2003 Capacity Additions Actual Availability was less than the 2003 Capacity Additions Ongoing Guaranteed Availability. Notwithstanding any provision of this Section 8.3.3, the 2003 Capacity Additions Actual Availability shall be calculated annually and shall not be recalculated as the result of any 2003 Capacity Additions Performance Test.

(d) Basis of Adjustments: Adjustments pursuant to this Section 8.3.3.4 shall be based on the 2003 Capacity Additions Capacity Charge in effect on the later of (a) the 2003 Capacity Additions Commercial Operation Date or (b) the end of the 2003 Capacity Additions Correction Period. During the 2003 Capacity Additions Correction Period, any adjustment shall be estimated based on

the 2003 Capacity Additions Capacity Charge then in effect and shall be trued-up in connection with the regular monthly billing immediately following the end of the 2003 Capacity Additions Correction Period.

(e) Limitation of Adjustments:

(i) Deadband: The 2003 Capacity Additions Capacity Charge shall not be adjusted pursuant to (a), (b) or (c) above if the difference between the guaranteed value and the actual value in such paragraph is less than two and one half percent (2.5%).

(ii) Maximum Adjustment: The Monthly Capacity Charge, as adjusted pursuant to this Section 8.3.3.4, shall not be reduced below an amount equal to one hundred percent (100%) of the greater of (a) the sum of (i) monthly principal and interest due with respect to all indebtedness incurred by HPP to finance the 2003 Capacity Additions, and (ii) property taxes and insurance with respect to the 2003 Capacity Additions, or (b) the amount necessary for HPP's net income before taxes with respect to the 2003 Capacity Additions, determined in accordance with generally accepted accounting principles, to be zero.

8.3.3.5. Uncompensated Failure to Meet 2003 Capacity Additions Ongoing Performance Guarantees: If the 2003 Capacity Additions Capacity Charge reduction as calculated pursuant to Section 8.3.3.4(a), (b) and (c) is greater than the actual reduction permitted as the result of the limits applicable pursuant to Section 8.3.3.4(e) for any thirty-six (36) consecutive Delivery Months, Tampa may, upon 120 days written notice to HPP purchase the property and rights described in Section 11.3 in accordance with the provisions of such section, unless within forty-five (45) days after such notice HPP pays to Tampa the aggregate deficiency between such calculated and actual charges during such thirty-six (36) months with interest calculated at the rate in Section 6.2.

8.3.3.6 Limited Remedies: Any adjustment made in the 2003 Capacity Additions Capacity Charge in accordance with this Section 8.3.3 shall, except as provided in Section 8.3.3.5, be Tampa's sole remedy for any failure to fulfill the 2003 Capacity Additions Ongoing Performance Guarantees under this Section 8.3.3 and such failure alone shall not be an Event of Default under this Agreement.

8.3.4. Maintenance Planning and Budgeting: By September 1 of each 2003 Capacity Additions Contract Year, HPP shall propose the 2003 Capacity Additions maintenance activities and associated maintenance budgets for the following 2003 Capacity Additions Contract Year. The Operating Committee shall, by October 15 of each 2003 Capacity Additions Contract Year, agree to and jointly approve the major maintenance activities and associated maintenance budgets for the following 2003 Capacity Additions Contract Year. Tampa shall not unreasonably withhold such approval. The agreed upon activities shall then

become the planned maintenance for the 2003 Capacity Additions for such 2003 Capacity Additions Contract Year.

Section 8.3 Supply and Transportation – Section 8.3 of the Tampa Agreement shall be renumbered Section 8.4 and amended to read as follows:

> 8.4 Fuel Supply and Transportation: HPP shall arrange for supply and transport of fuel for the CT/CC Facilities and the 2003 Capacity Additions in accordance with Prudent Utility Practice, which arrangements HPP believes in good faith to be the most suitable considering the total use of the Hardee Power Station. Under current market conditions, it is anticipated that natural gas delivered to the Site by pipeline, which may be on an interruptible basis, will be the primary fuel and that distillate fuel oil delivered to the Site by truck will be used as the alternate fuel in the event of unavailability of gas supply. In the event HPP arranges gas supply and transport which is partially or totally on a firm basis, the Parties shall, prior to the execution of the agreements reflecting such arrangements, negotiate an equitable sharing of the associated costs in proportion to the benefits projected to be derived by Tampa from such firm arrangements.
>
> 8.4.1 Cost of Gas Lateral: If such gas supply and transport arranged by HPP requires construction of a lateral pipeline from another pipeline to the Site, HPP shall be entitled to an equitable adjustment of the Monthly CT/CC Capacity Charge or the 2003 Capacity Additions Capacity Charge, as applicable, pursuant to Section 6.4.8.

Section 8.4 Compliance with Law – Section 8.4 of the Tampa Agreement shall be renumbered Section 8.5 and amended to read as follows:

> 8.5 Compliance with Law: HPP shall at all times conform to all applicable laws, ordinances, rules and regulations, the non-conformance with which could materially affect HPP's performance under this Agreement. HPP shall give all required notices, shall procure and maintain all governmental permits, licenses and inspections necessary for its performance of this Agreement.

ARTICLE IX.

AMENDMENTS RELATED TO EVENTS OF DEFAULT

Section 9.1 Rights of Lenders – Section 9.3 of the Tampa Agreement shall be amended to read as follows:

> 9.3 Rights of Lenders: HPP may encumber by mortgage or other proper instrument, its interest in the CT/CC Facilities and the 2003 Capacity

Additions, as appropriate given the context, and in the Tampa Agreement in order to finance the construction and operations of the CT/CC Facilities and the 2003 Capacity Additions. The execution of any mortgage, or other instrument, or the foreclosure thereof, or any sale thereunder, either by judicial proceedings or by virtue of any power reserved in such mortgage or indebtedness, or the exercising of any right, power or privilege reserved in any mortgage or other instrument, shall not be held as a violation of any of the terms and conditions hereof (and is hereby expressly permitted by Tampa), or as an assumption by the holder of such indebtedness (the "Lender") personally of the obligations under the Tampa Agreement (and the liability of such Lender shall be limited to the interest of such Lender in the CT/CC Facilities and/or the 2003 Capacity Additions, as appropriate given the context). No such encumbrance, foreclosure, conveyance or exercise of right shall relieve HPP from its liability under this Agreement. If HPP shall encumber its interest in all or any part of the CT/CC Facilities or the 2003 Capacity Additions or this Agreement, and if HPP or any Lender shall give notice to Tampa of the existence thereof and the address of such Lender, then Tampa will mail and deliver to such Lender, at such address, a duplicate copy of all notices of default and any other material notice that Tampa may, from time to time, give to or serve on HPP under and pursuant to the terms and provisions hereof. Such notice shall not be effective as to the Lender until given to it in accordance with these provisions. Such copies shall be mailed or delivered to such Lender at, or as near as possible to, the same time such notices are given to or served on HPP. Such Lender may, at its option, at any time before the rights of HPP shall be terminated as provided herein, pay any amounts due hereunder or do any act or thing required by HPP by the terms of this Agreement, or do any act or thing that may be necessary and proper to be done in the observance of the covenants and conditions of this Agreement, or prevent the exercise by Tampa of its rights pursuant to Section 8.2.1.1, 8.2.3.5, 8.3.1.1, 8.3.3.5, 9.2, 10.1.3 or 11.2 of this Agreement. All payments so made, and all things so done or performed by such Lender shall be as effective to prevent a termination of the rights of HPP under this Agreement as the same would have been if done and performed by HPP.

ARTICLE X

AMENDMENTS TO OPTIONS

Section 10.1 2003 Capacity Additions – Section 10.2 of the Tampa Agreement shall be amended to read as follows:

10.2 2003 Capacity Additions:

10.2.1 HPP and Tampa Options: The Parties acknowledge that Tampa has exercised its option to construct the 2003 Capacity Additions as provided in this Section 10.2.1. HPP shall construct the first phase of the 2003 Capacity

Additions, which shall consist of the CT 2B and is scheduled to be in service by May 15, 2000. Tampa shall exercise its option to require HPP to construct the remaining facilities of the 2003 Capacity Additions by written notice to HPP which shall be provided to HPP prior to December 1, 2000 and shall specify a scheduled in-service date for such remaining facilities of no later than June 1, 2003. In the event that Tampa has not provided such written notice to HPP by December 1, 2000, Tampa's option to require HPP to construct the remaining facilities of the 2003 Capacity Additions shall be deemed to be waived, effective as of December 1, 2000. If such written notice is provided by Tampa to HPP prior to December 1, 2000 but the first phase of the 2003 Capacity Additions is not placed in service prior to June 1, 2003, Tampa's option to require HPP to construct the remaining facilities of the 2003 Capacity Additions shall be deemed to be waived, effective as of June 1, 2003. In either case, upon the effective date of such waiver, neither Tampa nor HPP shall object to any request made by Seminole to any Governmental Authority, including the FDEP, to utilize the incremental capacity represented by the remaining facilities of the 2003 Capacity Additions (other than the CT 2B) pursuant to any regulatory authorization issued by such Governmental Authority so long as such request does not have an adverse impact on existing facilities or the CT 2B or their operation. In the event that Seminole utilizes the incremental capacity represented by such remaining facilities, the HPS Shared Common Facilities Capacity Charge Adjustment, the HPS Site Common Facilities Energy Charge and the HPS Plant Common Facilities Energy Charge payable by Tampa shall be equitably adjusted as provided for in Section 6.4.9.4.

Section 10.2 CC 2 Efficiency Rights Option: Section 10.2.2.1 of the Tampa Agreement shall be amended to read as follows:

10.2.2.1 CC 2 Efficiency Rights Option: In the event that Tampa elects to construct the second phase of the 2003 Capacity Additions, HPP shall make available to Seminole by written notice an option to acquire rights to the improved fuel efficiency of the portion of the capacity of the CC 2 to which Seminole's purchase rights are to apply (the "CC 2 Efficiency Rights"). The written notice shall include a firm monthly capacity charge and an estimated monthly energy charge reflecting the CC 2 Efficiency Rights. Such estimated energy charges shall include itemization of the components of such charges, including fuel cost, fixed and variable operations and maintenance cost, and administrative and general costs, including TECO Energy allocated costs as set forth in Appendix S. Within ninety (90) days of such notice from HPP, Seminole shall exercise such option or be deemed to have waived it. If Seminole elects to purchase the CC 2 Efficiency Rights, the Parties shall enter into an amendment to this Agreement, or at the request of HPP, an additional agreement in form and substance reasonably satisfactory to Seminole, making such purchase subject to

conditions precedent and on terms substantially equivalent to those of Seminole's rights in CC 1.

Section 10.3 Option to Purchase – Section 10.3.1 of the Tampa Agreement shall be amended to read as follows:

10.3 Option to Purchase:

10.3.1. Option: Tampa may, at its option, purchase as of January 1, 2013, all or part of the CT/CC Facilities and the 2003 Capacity Additions. Tampa shall exercise such option by providing written notice to HPP on or before January 21, 2008, and if Tampa has not exercised such option by such date, such option shall be deemed to have been waived. If Tampa purchases all of the generating facilities on the Site owned by HPP, the purchase shall include the HPS Shared Common Facilities. If Tampa purchases less than all such generating facilities, the purchase shall include an undivided interest in such HPS Shared Common Facilities in an amount as will result, after the sale, in Tampa owning a percentage of the HPS Site Common Facilities equal to its percentage of nominal capacity in the Hardee Power Station and a percentage of the HPS Plant Common Facilities equal to Tampa's percentage of nominal capacity in HPS #1 and #2. Tampa, or its successor in interest, shall negotiate with other owners of the Hardee Power Station any modifications to the Monthly Capacity Charge, ground lease rentals, Monthly Energy Charge and other related expenses and arrangements included in or related to this Agreement equitably necessary to reflect and allow the new division of use of the Site and the facilities thereon. In no event shall Tampa's exercise of this option change Seminole's priority rights in the CC 1.

Section 10.4 Capital Additions – Section 10.4 of the Tampa Agreement shall be amended to read as follows:

10.4 Capital Additions: In the event that, during the term of this Agreement, the Parties agree to make modifications to the CT/CC Facilities or the 2003 Capital Additions that require capital additions, the Monthly CT/CC Capacity Charge and/or the 2003 Capacity Additions Capacity Charge, as applicable, shall be equitably adjusted in accordance with Section 6.4.8. If the Parties do not agree with respect to a capital addition, HPP at its option may, or Tampa may at its option require HPP to make such modification to the CT/CC Facilities or the 2003 Capital Additions, provided that such modification shall not interfere with the operation of such Facilities or such Additions in any material way, and further provided that the Monthly CT/CC Capacity Charge and/or the 2003 Capacity Additions Capacity Charge shall be equitably adjusted in accordance with Section 6.4.8 to impose upon the Party requiring such modification the entire cost.

ARTICLE XI.

AMENDMENTS TO CONDITIONS PRECEDENT

Section 11.1 Purchase of CT/CC Facilities and 2003 Capacity Additions – Section 11.3 shall be amended to read as follows:

11.3 Purchase of CT/CC Facilities and 2003 Capacity Additions: In connection with the purchase of the CT/CC Facilities and the 2003 Capacity Additions by Tampa pursuant to Sections 8.2.1.1, 8.2.3.5, 10.1.3 and 11.2, the following provisions shall apply:

(a) If Tampa has not acquired purchase rights under Section 10.3.1 and HPP by January 21, 2008 has constructed or entered into material binding commitments to construct all or part of the 2003 Capacity Additions and the commercial operation date of the second phase of the 2003 Capacity Additions is reasonably expected to occur on or before January 1, 2013, Tampa's purchase option shall be limited to the CC 1.

(b) If Tampa purchases all the generating facilities on the site owned by HPP, the purchase shall include all appurtenant common and supporting facilities used and useful in connection with the operation of the CT/CC Facilities and the 2003 Capacity Additions. If Tampa purchases less than all such generating facilities, the purchase shall include an undivided interest (proportional to the share of the capacity in HPS #1 and #2 Tampa is then purchasing) in common and supporting facilities in such amount as will result, after the sale, in Tampa owning a percentage of the HPS Site Common Facilities equal to its percentage of nominal capacity in the Hardee Power Station and a percentage of the HPS Plant Common Facilities equal to Tampa's percentage of nominal capacity in HPS #1 and #2. Tampa, or its successor in interest, shall negotiate with other owners of the Hardee Power Station, or their successor in interest, any modifications to the Monthly Capacity Charge, ground lease rentals, Monthly Energy Charge and other related expenses and arrangements included in or related to this Agreement equitably necessary to reflect and allow the new division of use of the Site and the facilities thereon.

(c) The purchase price for such property and rights shall be the greater of (i) the Fair Market Value of such property and (ii) the sum of all outstanding principal, interest and other amounts payable to Lenders in respect of debt incurred by HPP to finance the construction of the CT/CC Facilities and the 2003 Capacity Additions plus, except in the case of a purchase pursuant to Section 8.2.3.5 or Section 8.3.3.5, the amount of any unreimbursed eligible costs paid or incurred by HPP with respect to the CT/CC Facilities or the 2003 Capacity Additions. Eligible costs shall mean those amounts that would be reimbursed or paid from the proceeds of 100% project financing of either the CT/CC Facilities or the 2003 Capacity Additions, as appropriate given the context, to the extent

that such Facilities or Additions were completed on schedule and in conformance with the Performance Guarantees. Such price may be payable, to the extent permitted by the applicable instruments, by assumption of the debt, with the balance payable in cash.

(d) In connection with such purchase, Tampa shall be entitled to all rights of HPP and assume the obligations of HPP under all outstanding agreements relating to the CT/CC Facilities and the 2003 Capacity Additions, including without limitation, the Seminole Agreement.

(e) HPP shall deliver to Tampa and Tampa shall deliver to HPP and any Lender any and all documents and instruments necessary to reflect such assignment and assumption under the foregoing paragraphs or make other arrangements reasonably required by HPP with respect to the indebtedness.

ARTICLE XII.

FORCE MAJEURE AND INDEMNIFICATION

12.1 Force Majeure and Indemnification – The following Section 12.1.1 shall be added to the Tampa Agreement as follows:

12.1.1 Force Majeure: For purposes of Section 12.1 of the Tampa Agreement, a delay in the approval by the FDEP of the modification of the conditions of certification required prior to commencing construction of the first phase of the 2003 Capacity Additions shall constitute Force Majeure.

ARTICLE XIII.

EFFECTIVE DATE

Section 13.1 Effective Date – This Fourth Amendment shall be effective on the later to occur of (i) the date on which this Fourth Amendment and the Fourth Amendment to the Seminole Agreement are accepted for filing by the FERC and allowed to become effective and (ii) the date on which the Fourth Amendment to the Seminole Agreement is approved by the Administrator of the Rural Utilities Service, provided, however, that if the FERC does not accept this Fourth Amendment and/or the Fourth Amendment to the Seminole Agreement for filing without change or condition and HPP determines that the change or condition imposed or

that may be imposed by the FERC would prevent HPP from securing long-term, limited-recourse debt financing of the CT 2B on terms and conditions reasonably acceptable to HPP, HPP shall have the right to terminate this Fourth Amendment and the Fourth Amendment to the Seminole Agreement upon twenty (20) days prior written notice to Tampa and Seminole.

[Signatures on next page]

IN WITNESS WHEREOF, the Parties hereto have caused this Fourth Amendment to the Tampa Agreement to be executed by their fully authorized officers, and copies delivered to each party, as of the first day above written.

HARDEE POWER I, INC.
acting as General Partner of
HARDEE POWER PARTNERS LIMITED

WITNESSES:

By: _____

Title: President

TAMPA ELECTRIC COMPANY

WITNESSES:

By: _____

Title: President

APPENDIX F

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBUSTION TURBINE FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated With 1993 Non-Coal Facilities (Sum of Lines 1 Through 14; See Note 4)		

16 Percent Allocable to Tampa: 40% for all accounts except Account 550. See Note 2 for Account 550 percentage.

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33. Tampa's allocation for the portion of this account that is for the annual site lease costs is 59.77%. Tampa's allocation for the remaining portion of this account shall be 40%.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX G

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBUSTION TURBINE VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With 1993 Non-Coal Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance For 1993 Non-Coal Facilities (Appendix F, Line 15)	

17 Total Variable Operation & Maintenance For 1993 Non-Coal Facilities (Line 15 – Line 16)

18 Operation & Maintenance Allocated to Off-System Sales

19 Total Variable O&M For 1993 Non-Coal Facilities To Be Allocated (Line 17 – Line 18)

20 Energy Generated by the CT Unit for Tampa During the Previous Twelve Month Period Ending With the Delivery Month

21 Total Energy Generated By the CT Unit During the Previous Twelve Month Period Ending With the Delivery Month

22 Energy Generated by the CT Unit for Off-System Sales During the Previous Twelve Month Period Ending With the Delivery Month

23 Total Net Energy Generated By the CT Unit Exclusive of Energy Generated for Off-System Sales (Line 21 – Line 22)

24 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 20 divided by Line 23)

25 Total Variable O&M Allocable to Tampa Associated With Tampa's Sales of Schedules A and B Interchange Service

26 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities ((Line 19 x Line 24) + Line 25)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation an Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX H

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBUSTION TURBINE ADMINISTRATIVE AND GENERAL EXPENSES

For purposes of this Agreement, the "Delivery Month Administrative and General Expenses Allocated to the CT Unit," identified in Section 6.5.1 (d) shall be determined as follows:

Line	Description
1	920-932 Administrative & General Expenses
2	Less: Production Property Insurance Included in Account 924
3	920-932 Administrative & General Expenses Excluding Production Property Insurance (Line 1 – Line 2) (See Note 1)
4	CT Unit MW Capacity
5	Total CT/CC Facilities MW Capacity
6	Percent Allocable to CT Unit (Line 4 divided by Line 5)
7	A&G Allocable to CT Unit (Line 3 x Line 6)
8	Percent Allocable to Tampa: 40% Commencing on the 2003 Capacity Additions Energy Charge Effective Date, percentage allocable to Tampa: 59.77%
9	A&G Expense Allocable to Tampa (Line 7 x Line 8)

Note 1: Included only those expenses directly charged to the CT/CC Facilities, the 2003 Capacity Additions and Allocable Costs from TECO Energy, Inc. per Appendix S. Administrative and General services by TECO Energy subsidiaries will be provided at cost. Direct charges shall include only those expenses which provide a benefit to the CT/CC Facilities and the 2003 Capacity Additions. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from

TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX J

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBINED CYCLE FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.2 (b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated With 1993 Non-Coal Facilities (Sum of Lines 1 Through 14; See Note 4)		
16	Percent Allocable to Tampa: 40%. See Note 2 for Account 550 percentage.		

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33. Tampa's allocation for the portion of this account that is for the annual site lease costs is 59.77%. Tampa's allocation for the remaining portion of this account shall be 40%.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CC 1 (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX K

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBINED CYCLE VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.2 (b) shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With 1993 Non-Coal Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance For 1993 Non-Coal Facilities (Appendix J, Line 15)	

17 Total Variable Operation & Maintenance For 1993 Non-Coal Facilities (Line 15 - Line 16)

18 Operation & Maintenance Allocated to Off-System Sales

19 Total Variable O&M For 1993 Non-Coal Facilities To Be Allocated (Line 17 - Line 18)

20 Energy Generated by the CC 1 for Tampa During the Previous Twelve Month Period Ending With the Delivery Month

21 Total Energy Generated By the CC 1 During the Previous Twelve Month Period Ending With the Delivery Month

22 Energy Generated by the CC 1 for Off-System Sales During the Previous Twelve Month Period Ending With the Delivery Month

23 Total Net Energy Generated By the CC 1 Exclusive of Energy Generated for Off-System Sales (Line 21 – Line 22)

24 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 20 divided by Line 23)

25 Total Variable O&M Allocable to Tampa Associated With Tampa's Sales of Schedules A and B Interchange Service

26 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities ((Line 19 x Line 24) + Line 25)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CC 1 (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX L

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBINED CYCLE ADMINISTRATIVE AND GENERAL EXPENSES

For purposes of this Agreement, the "Delivery Month Administrative and General Expenses Allocated to the Combined Cycle Units," identified in Section 6.5.2 (d) shall be determined as follows:

Line	Description
1	920-932 Administrative & General Expenses
2	Less: Production Property Insurance Included in Account 924
3	920-932 Administrative & General Expenses Excluding Production Property Insurance (Line 1 – Line 2) (See Note 1)
4	Combined Cycle Units' MW Capacity
5	Total CT/CC Facilities MW Capacity
6	Percent Allocable to Combined Cycle Units (Line 4 divided by Line 5)
7	A&G Allocable to Combined Cycle Units (Line 3 x Line 6)
8	Percent Allocable to Tampa: 40% Commencing on the 2003 Capacity Additions Energy Charge Effective Date, percentage allocable to Tampa: 59.77%
9	A&G Expense Allocable to Tampa (Line 7 x Line 8)

Note 1: Included only those expenses directly charged to the CT/CC Facilities, the 2003 Capacity Additions and Allocable Costs from TECO Energy, Inc. per Appendix S. Administrative and General services by TECO Energy subsidiaries will be provided at cost. Direct charges shall include only those expenses which provide a benefit to the CT/CC Facilities and the 2003 Capacity Additions. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, in no event shall such expenses

include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX U

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

REPLACEMENT OF COMBINED CYCLE PROPERTY UNITS EXPENSE

For purposes of this Agreement, the "Delivery Month Fixed Charges for Replacement Property Units" identified in Section 6.5.2 (c) shall be determined as follows:

Line	Description
1	Expenditures (Net of Salvage Value) for Replacement of Property Units of the CC 1 - Current Month (Note 1)
2	Expenditures for Replacement of Property Units from Inception of Agreement to End of Prior Month (Per Prior Bill – Line 3)
3	Cumulative Expenditures for Replacement of Property Units of the CC 1 from Inception of Agreement to End of Current Month (Line 1 + 2)
4	Fixed Charge Rate (14.67% Annually/12): 1.222%
5	Current Month Fixed Charges for Property Units Replaced on the CC 1 (Line 3 x Line 4)
6	Percent Allocable to Tampa: 40%
7	Delivery Month Fixed Charges for Property Units Replaced on the CC 1 and Allocable to Tampa (Line 5 x Line 6)

Note 1: Includes only those capitalized expenditures for the replacement of property units which existed, per design specifications, on the date that the CC 1 in question was placed in commercial operation, or as subsequently modified by mutual agreement of the Parties or as otherwise determined by the Operating Committee from time to time. HPP shall define the property units and submit such definitions to the Operating Committee for review and approval.

APPENDIX V

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

HPS PLANT COMMON FACILITIES

FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs associated with the utilization of the HPS Plant Common Facilities" excluding fuel, identified in Section 6.5.5 shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated with HPS Plant Common Facilities (Sum of Lines 1 Through 14; See Note 4)		
16	Percent Allocable to Tampa: 59.77%.		

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR HPS PLANT COMMON FACILITIES (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Plant Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX W

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

HPS PLANT COMMON FACILITIES

VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Plant Common Facilities" excluding fuel, identified in Section 6.5.5 shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With HPS Plant Common Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance Associated With HPS Plant Common Facilities (Appendix V, Line 15)	

17 Total Variable Operation & Maintenance Associated With HPS Plant Common Facilities To Be Allocated (Line 15 – Line 16)

18 Energy Generated for Tampa from HPS #1 and #2 During the Previous Twelve Month Period Ending With the Delivery Month

19 Total Energy Generated from HPS #1 and #2 During the Previous Twelve Month Period Ending With the Delivery Month

20 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 18 divided by Line 19)

21 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR HPS PLANT COMMON FACILITIES (Line 17 x Line 20)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Plant Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX X

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

HPS SITE COMMON FACILITIES

FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities" excluding fuel, identified in Section 6.5.3 shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated with HPS Site Common Facilities (Sum of Lines 1 Through 14; See Note 4)		

16 Percent Allocable to Tampa commencing on the 2003 Capacity Additions Energy Charge Effective Date: 53.18%.

Percent Allocable to Tampa commencing on the HPS #3 Energy Charge Effective Date: 37.82%.

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR HPS SITE COMMON FACILITIES (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Site Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX Y

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

HPS SITE COMMON FACILITIES

VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities" excluding fuel, identified in Section 6.5.3 shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With HPS Site Common Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance Associated With HPS Site Common Facilities (Appendix X, Line 15)	

17 Total Variable Operation & Maintenance Associated With HPS Site Common Facilities To Be Allocated (Line 15 – Line 16).

18 Energy Generated for Tampa from HPS #1 and #2 During the Previous Twelve Month Period Ending With the Delivery Month

19 Total Energy Generated from HPS #1 and #2 and HPS #3 During the Previous Twelve Month Period Ending With the Delivery Month

20 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 18 divided by Line 19)

21 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR HPS SITE COMMON FACILITIES (Line 17 x Line 20)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses associated with the HPS Site Common Facilities. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX Z

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

2003 CAPACITY ADDITIONS

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs and Delivery Month Variable Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.4(b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 1
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 1
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	See Note 1
8	553	Maintenance of Generation & Electric Plant	See Note 1
9	554	Maintenance of Misc. Other Power Generation	See Note 1
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	See Note 1
13	570	Maintenance of Station Equipment	See Note 1
14	571	Maintenance of Overhead Lines	See Note 1
15	Total Delivery Month Operation and Maintenance Associated with the 2003 Capacity Additions (Sum of Lines 1 Through 14; See Note 1)		
16	Percent Allocable to Tampa: 100%		

17 TOTAL OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR THE 2003 CAPACITY ADDITIONS (Line 15 x Line 16)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the 2003 Capacity Additions. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX AA

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

REPLACEMENT OF 2003 CAPACITY ADDITIONS PROPERTY UNITS EXPENSE

For purposes of this Agreement, the "Delivery Month Fixed Charges for Replacement Property Units" identified in Section 6.5.4 (c) shall be determined as follows:

Line	Description
1	Expenditures (Net of Salvage Value) for Replacement of Property Units of the 2003 Capacity Additions – Current Month (Note 1)
2	Expenditures for Replacement of Property Units from Inception of Agreement to End of Prior Month (Per Prior Bill – Line 3)
3	Cumulative Expenditures for Replacement of Property Units of the 2003 Capacity Additions from Inception of Agreement to End of Current Month (Line 1 + 2)
4	Fixed Charge Rate (14.67% Annually/12): 1.222%
5	Current Month Fixed Charges for Property Units Replaced on the 2003 Capacity Additions (Line 3 x Line 4)
6	Percent Allocable to Tampa: 100%
7	Delivery Month Fixed Charges for Property Units Replaced on the 2003 Capacity Additions and Allocable to Tampa (Line 5 x Line 6)

Note 1: Includes only those capitalized expenditures for the replacement of property units which existed, per design specifications, on the date that the 2003 Capacity Additions was placed in commercial operation, or as subsequently modified by mutual agreement of the Parties or as otherwise determined by the Operating Committee from time to time. HPP shall define the property units and submit such definitions to the Operating Committee for review and approval.

APPENDIX BB

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

2003 CAPACITY ADDITIONS PERFORMANCE GUARANTEES

1. The 2003 Capacity Additions Performance Guarantees are as follows:

Operating Point	Guaranteed Net Electrical Output (KW)	Guaranteed Net Heat Rate (BTU/KWHR, LHV)
Base Load	82,444	10,677

2. Availability Calculation

The 2003 Capacity Additions Actual Availability shall be determined as follows:

2003 Capacity Additions Actual Availability = ([PH – (FOH + MOH + POH)] / PH) x 100%

Where:

PH is the number of clock hours in the period under consideration

FOH is the time in hours during which the unit was unavailable due to a forced (unplanned) outage, as adjusted pursuant to Section 8.3.3.3 (b).

MOH is the time in hours during which the unit was unavailable due to a maintenance outage.

POH is the time in hours during which the unit was unavailable due to a planned outage.

3. Basis for Performance Guarantees

The 2003 Capacity Additions Performance Guarantees listed in Section 1 of this Appendix are based on the scope of supply in the 2003 Capacity Addition Construction Contract and the following:

3.1. Natural Gas in compliance with General Electric's Process Specification for Fuel Gases For Combustion In Heavy-Duty Gas Turbines No GEI 41040F. Fuel temperature prior to the fuel gas heater at 50 degrees F and at the turbine skid at 90 degrees F.

3.2. Ambient Conditions at 59 degrees F, 14.64 psia, and 60% relative humidity.

3.3. Gas turbine is at steady state base load operation.

3.4. Gas turbine exhaust temperature is within 2 degrees F of the value specified by the control curve.

3.5. Generator gross output and unit auxiliary load are measured at 13.8 kV (the low side of the generator step-up transformer). Guaranteed Net Electrical Output and Guaranteed Net Heat Rate are calculated based on the measurement of generator gross output less unit auxiliary kilowatts power consumption ($P_{net} = P_{gross} - P_{aux}$). Fuel consumption is measured at the unit custody transfer meter.

APPENDIX CC

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNOR OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

PROCEDURES FOR TESTING THE 2003 CAPACITY ADDITIONS

1. Simple Cycle Test Procedure

The test procedures for the 2003 Capacity Additions Performance Tests determining the 2003 Capacity Additions Commercial Operation Date will be based upon the American Society of Mechanical Engineers Power Test Code PTC-22-1997 "Gas Turbine Power Plants" (" PTC 22") with the following additions and/or exceptions. The figures in parenthesis refer to the relevant paragraph in PTC 22.

A. A valid test run will consist of thirteen (13) sets of instrument readings taken at five (5) minute intervals over a sixty (60) minute time span after steady state conditions have been established in accordance with PTC-22.

A test run shall be considered valid as long as the output and basis condition parameters doe not deviate from the average over the test run by more than an amount to be mutually agreed by the parties as recommended by PTC-46.

The CT 2B will be considered to be in a steady state condition when turbine wheelspace temperatures do not change more than five (5) degrees F in fifteen minutes prior to the test point.

B. Speed measurements are required, and must be measured by an electronic tachometer or equal at the SPEEDTRONIC panel and averaged for the test run. Any corrections for frequency variations shall be applied to the calculation.

C. The average CT 2B gross electrical output is to be measured by polyphase watthour revenue meters at the generator terminals. Net electrical output will be the gross electrical output less the CT 2B auxiliary loads. Revenue quality metering to be provided by contractor.

D. Gas Turbine Exhaust temperature will be measured by the unit control thermocouples mounted in the exhaust plenum. (4.56) It is essential that the temperature indicating system be adjusted and calibrated in place with a known millivolt source prior to the test so that it reports reliable data. If more than 25 percent of the thermocouples are inoperative, the test shall not be valid.

E. When liquid-in-glass manometers are used, bores of smaller than 5/16" will be permitted. (4.59)

F. Barometric Pressure at the test site shall be measured with a precision mercury or aneroid barometer with an accuracy in accordance with PTC-22. A minimum reading accuracy of 0.01 in Hg is required. (4.65)

G. Not Used.

H. Fuel Consumption

Natural gas is to be measured in accordance with ASME or AGA standards. The upstream pressure will be measured with a precision test gage, the gas temperature with a thermometer or thermocouple.

Four (4) samples must be taken from the fuel system during the test for laboratory measurement of higher heating value and specific gravity.

Calculation of gas flow will be done in accordance with ASME or AGA standards as described in ASME PTC 19.5; 1972 or AGA Report #3.

I. Inlet air condition will be measured with at least four (4) thermometers or thermocouples installed.

J. Turbine exhaust static pressure at or near the turbine exhaust flange or other convenient location must be measured using at least two (2) disc type static pressure probes.

K. When the tests are performed, the gas turbine control system must be adjusted to operate at the correct average gas turbine exhaust temperature for the test conditions as defined by the appropriate control curve.

M. All instruments to be used in the 2003 Capacity Additions Performance Test shall be calibrated in the field and witnessed by the appropriate parties prior to such test.

2. Annual 2003 Capacity Additions Performance Tests

Testing to demonstrate 2003 Capacity Additions Ongoing Performance Guarantees subsequent to the 2003 Capacity Additions Commercial Operation Date will be performed using procedures which are mutually agreed upon by the Parties.

Exhibit No. ____ (WLB-2),
Document No. 2

DOCUMENT NO. 2
PAGE 1 OF 39
FILED: 11/1/99

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

99 SEP 15 PM 4:47
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of:	)	
	)	ER99- -000
Hardee Power Partners Limited	)	

PETITION OF HARDEE POWER PARTNERS LIMITED FOR AN ORDER ACCEPTING RATES

I. INTRODUCTION

Pursuant to Rules 205 and 207 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.205 and 385.207 (1998), and Sections 35.12 and 35.13 of the Commission's Regulations, 18 C.F.R. §§ 35.12 and 35.13 (1998), Hardee Power Partners Limited ("HPP") submits this abbreviated rate filing in connection with amendments to two power sales agreements ("Third Amendments" or "Amendments") providing for the sale by HPP of electric capacity and associated energy to Seminole Electric Cooperative, Inc. ("Seminole") and Tampa Electric Company ("Tampa Electric") from the Hardee Power Station, the rates under which were previously accepted by the Commission.[1] The Amendments filed herein implement the provisions of the original agreements which contemplate the construction by Seminole of the Payne Creek Generating Station at the same site on which the Hardee Power Station is situated ("Site")[2] and reflect certain related changes in the rates under the power sale agreements pursuant to the terms of

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1 TECO Power Services Corporation, 53 FERC ¶ 61,202 (1990).

2 The Site is a 465-acre parcel of land contiguous to the Tampa Electric service territory which has been leased by Acuera Corporation, a subsidiary of Seminole, to TECO Power Services Corporation ("Power Services"), HPP's predecessor in interest. See infra footnote 7 and accompanying text.

those agreements. The rate changes reflected within the Third Amendments affect the existing rates under the power sales agreements only with respect to the reallocation of various costs associated with certain common facilities on the Site, specifically the HPS Site Common Facilities.[3] Since Seminole's utilization of the HPS Site Common Facilities will increase as a result of its construction of the Payne Creek Generating Station, its rates will increase solely to reflect the reallocation of the costs of these common facilities; conversely, since Tampa Electric's relative utilization of the HPS Site Common Facilities will decrease, its rates under its power sales agreement will decrease. As further described herein, HPP requests waiver of the Commission's 60-day notice requirement and an effective date of November 1, 1999.

Contemporaneously with the filing of this Petition, HPP is filing a second petition submitting amendments to the same two power sales agreements ("Fourth Amendments"). The Fourth Amendments implement the provisions of the power sales agreements under which Tampa Electric has exercised the option to require HPP to construct additional generation facilities, necessitating a reallocation of the costs of the HPS Site Common Facilities and the HPS Plant Common Facilities. In addition, the Fourth Amendment to the Tampa Electric power sales agreement sets forth the rates, terms, and conditions pursuant to which HPP will sell to Tampa Electric the capacity and associated energy from the additional generation to be built at the Hardee Power Station.

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[3] The HPS Site Common Facilities are the access roads, the cooling reservoir, the natural gas pipeline, the switchyard, the water wells, and pumps and the Site itself, all of which will be shared by the Hardee Power Station and the Payne Creek Generating Station. The Third Amendments to the Tampa Electric and Seminole Agreements submitted for filing herein involve a reallocation of the costs of the HPS Site Common Facilities.

II. COMMUNICATIONS

All service and correspondence concerning this Application should be addressed to:

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and

Linda A. Miller
Vice President
Hardee Power Partners Limited
702 North Franklin Street
Tampa, Florida 33602
(813) 228-1311

III. BACKGROUND

On January 18, 1990, TECO Power Services Corporation ("Power Services"), HPP's predecessor in interest, and Tampa Electric filed for approval of the rates under three power sales agreements in Docket No. ER90-164 ("January 18 Application"). The three agreements were (1) the Agreement for Sale and Purchase of Capacity and Energy between TECO Power Services Corporation and Seminole Electric Cooperative, Inc. (the "Seminole Agreement"); (2) the Agreement for Sale and Purchase of Capacity and Energy from the Hardee Power Station between TECO Power Services Corporation and Tampa Electric Company (the "Tampa Electric Agreement") ("collectively, the "Power Sales Agreements" or the "Agreements"); and (3) the Agreement for Sale and Purchase of Capacity and Energy from Big Bend Station Unit No. 4 ("BB4") between TECO Power Services Corporation and Tampa Electric Company (the "BB4

Agreement").[4] The Power Sales Agreements and the BB4 Agreement form an integrated transaction in which HPP (1) has constructed, owns, and operates the Hardee Power Station;[5] (2) sells for twenty years the capacity and energy produced by the Hardee Power Station to Seminole and Tampa Electric pursuant to the Seminole and Tampa Electric Agreements, respectively; and (3) purchases for ten years certain rights to 145 MW of capacity and energy from Tampa Electric for resale to Seminole pursuant to the BB4 Agreement. The agreements were initially developed in response to Seminole's 1988 request for proposals to provide 440 MW of back-up power to Seminole over a twenty-year period commencing January 1, 1993. These agreements were negotiated and finalized at the conclusion of that bidding program and represented at the time an innovative mix of new and existing generating capacity to meet the complementary capacity and energy needs of Seminole and Tampa Electric.

On November 19, 1990, the Commission accepted the three agreements for filing, finding that the costs of the Hardee Power Station, including the equity allowance, and the allocation of those costs between Seminole and Tampa Electric to be reasonable.[6] The Commission designated the three agreements as follows: (1) the Seminole Agreement was designated as TECO Power Services, Inc., Rate Schedule FERC No. 1; (2) the Tampa Electric Agreement was designated as TECO Power Services, Inc., Rate Schedule FERC No. 2; and (3) the BB4 Agreement was designated as Tampa Electric Company, Rate Schedule FERC No. 33.

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[4] The BB4 Agreement provides for the sale by Tampa Electric to Power Services of an entitlement to 145 MW of capacity and energy from Tampa Electric's BB4 coal-fired facility for a ten-year period commencing on January 1, 1993.

[5] The Hardee Power Station provides 295 MW of generating capacity, consisting of a 220 MW combined cycle unit ("CC 1") and a 75 MW combustion turbine ("CT 2A"), and uses natural gas as its primary fuel and No. 2 fuel oil as a back-up fuel. In the Amendments, these facilities are referred to as the CT/CC Facilities.

[6] TECO Power Services Corporation, 53 FERC ¶ 61,202 at 61,811-13.

On December 21, 1990, Power Services filed with the Commission an application for authorization to transfer all of its rights, title, and interest in the Facility to HPP in order to facilitate financing of the Facility. The transfer of all project agreements and rights to develop the project was approved by the Commission in March 1991.[7] The Seminole and Tampa Electric Agreements were redesignated Hardee Power Partners Limited, Rate Schedules FERC Nos. 1 and 2, respectively, by letter order dated May 23, 1991 in Docket No. ER91-372-000.[8]

IV. PARTIES TO THE TRANSACTION

A. Hardee Power Partners Limited

HPP is a Florida limited partnership of which Hardee Power I, Inc. ("Hardee Power I") is the sole general partner, and Hardee Power II, Inc. ("Hardee Power II") is the sole limited partner. Hardee Power I has a twenty-five percent ownership interest in HPP with Hardee Power II owning the remaining seventy-five percent interest. Both Hardee Power I and Hardee Power II are Florida corporations which are wholly-owned subsidiaries of Power Services formed for the purpose of holding the partnership interests in HPP. Power Services is a wholly-owned subsidiary of TECO Energy, Inc. ("TECO Energy"), a utility holding company exempt from registration under Section 3(a)(1) of the Public Utility Holding Company Act of 1935 because of the intrastate nature of TECO Energy's utility business.

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[7] TECO Power Services Corporation, 54 FERC ¶ 62,172 (1991).

[8] On November 2, 1992 in Docket Nos. ER93-109-000 and ER93-134-000 and on September 20, 1993 in Docket No. ER93-966-000, HPP filed certain adjustments to the monthly capacity charge payable by Seminole and Tampa Electric, both of which resulted in a net decrease in the rates charged to the customers. The Commission accepted these revised rates for filing by letter orders issued on December 29, 1992 and November 12, 1993, respectively.

B. Seminole

Seminole is an electric generation and transmission cooperative incorporated in the State of Florida to provide wholesale electric service to eleven member rural electric distribution cooperatives. Seminole was originally formed in 1948 to represent its members in wholesale power purchase negotiations and, since 1974, has developed its own power supply resources. As of December 1998, the eleven member cooperatives serviced by Seminole supplied electricity to over 660,000 customers located in 45 of Florida's 67 counties.

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Tampa Electric is a regulated electric utility that is subject to the jurisdiction of the Florida Public Service Commission and has been serving the West Central Florida region since 1899. Tampa Electric currently serves over 537,000 customers in a service territory that covers over 2,000 square miles including the City of Tampa. Tampa Electric is also a wholly-owned subsidiary of TECO Energy and is its largest subsidiary, accounting for approximately 63% of total operating revenues generated from all operations in 1998.

V. THE POWER SALES AGREEMENTS

A. The Seminole Agreement

The Seminole Agreement encompasses the terms and conditions of HPP's sale to Seminole of an entitlement to 295 MW of capacity and corresponding energy produced at the Hardee Power Station for a term of twenty years. Seminole is given first priority to this capacity and the corresponding energy when needed to satisfy its back-up power needs.[9] The Seminole Agreement also provides for HPP's sale to Seminole of 145 MW of BB4 capacity and

[9] A full description of the Seminole and the Tampa Electric Agreements is set forth in the January 18 Application.

corresponding energy purchased by HPP from Tampa Electric for a ten-year period commencing on January 1, 1993. This capacity and energy can be called upon by Seminole without regard to outages of its own units but is subject to specified annual energy limitations.

The rates under the Seminole Agreement include both a Monthly Capacity Charge and a Monthly Energy Charge.[10] For the first ten years of the Seminole Agreement, the Monthly Capacity Charge is the sum of the Monthly CT/CC Capacity Charge (for the purchase of the capacity of the Hardee Power Station) and the Monthly BB4 Capacity Charge (passing through to Seminole the rates paid by HPP to Tampa Electric for the purchase of capacity and associated energy from BB4). During the second ten-year period, the Monthly Capacity Charge is the Monthly CT/CC Capacity Charge.[11]

The Monthly Energy Charge is the sum of the energy charges for BB4 ("Monthly BB4 Cost") and the Hardee Power Station (the sum of the "Monthly Combustion Turbine Cost" and the "Monthly Combined Cycle Cost"). The calculation of the Monthly Energy Charge is determined based upon Seminole's actual energy usage from both BB4 and the Hardee Power Station during each month. The Monthly BB4 Cost is based on Seminole's pro-rata share (based on actual energy usage) of fuel costs, production, operation and maintenance expenses, and pre-established administrative and general expenses. The Monthly Combustion Turbine Cost and Monthly Combined Cycle Cost provide for the recovery of Seminole's pro-rata share (based

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[10] The Seminole Agreement (and the Tampa Electric Agreement, discussed below) sets forth in detail the allocation of risks between the parties for construction and operating performance. Please see the description of the Agreements in the January 18 Application.

[11] Seminole's Monthly CT/CC Capacity Charge is subject to a maximum 33% reduction based upon the actual performance of the Hardee Power Station both at initial operation and during ongoing operations. The Agreement also contains a formula to adjust the Monthly CT/CC Capacity Charge to account for certain events, such as (a) a change in financing rates or federal or state income tax rates, (b) the exercise by Seminole of its option to purchase capacity and energy from an expansion of the Hardee Power Station, or (c) the occurrence of certain specified contingencies.

upon actual energy usage) of fuel and variable operation and maintenance costs, and for the recovery of 60% of (1) the fixed costs of operation and maintenance, (2) the cost of replaced property units, and (3) administrative and general expenses.

Section 7.6 of the Seminole Agreement provides that Seminole may construct its own 220 MW combined cycle generating plant on the Site. In the event that Seminole elects to construct this facility, the Seminole Agreement provides that HPP will share with Seminole the use of certain common facilities (including facilities specifically listed in the Seminole Agreement) based on Seminole being responsible for an equitable share of the cost of necessary modifications, expansions, or adjustments to the common facilities necessary to support such capacity and an equitable share of any increase in operation and maintenance costs with respect to such common facilities. Furthermore, to the extent that there is a benefit to sharing of operation and maintenance resources to support all facilities on the Site, the Seminole Agreement provides that HPP and Seminole will develop appropriate arrangements that share the costs and benefits of such shared facilities equitably. As discussed below, the modifications to the Seminole Agreement in the Third Amendment implement Section 7.6 of the Seminole Agreement.

B. The Tampa Electric Agreement

The Tampa Electric Agreement contains the terms and conditions of HPP's sale to Tampa Electric of an entitlement to 295 MW of capacity and associated energy from the Hardee Power Station for a twenty-year period commencing on January 1, 1993, with a potential expansion of such facilities to 440 MW for the final ten years of the contract term. The capacity and energy is utilized by Tampa Electric to meet its peaking power requirements. Tampa Electric is entitled to the capacity at any time to meet its native load or firm power commitments except to the extent that it is being utilized by Seminole to meet its back-up power requirements.

The pricing of capacity and energy from the Hardee Power Station sold by HPP to Tampa Electric mirrors the provisions of the Seminole Agreement described above, except that Tampa Electric is allocated 40% of (1) the fixed costs of operation and maintenance, (2) replaced property units, and (3) administrative and general expenses. Tampa Electric also pays a pro-rata share (based upon actual energy usage) of fuel and variable operation and maintenance costs. In most respects, the Tampa Electric Agreement essentially mirrors the Seminole Agreement, with certain limited exceptions.[12]

VI. EXERCISE OF SEMINOLE'S OPTION UNDER THE SEMINOLE AGREEMENT

Seminole has decided to exercise its right under Section 7.6 of the Seminole Agreement to construct the Payne Creek Generation Station (also known as Hardee Power Station, Unit No. 3 ("HPS #3")), a combined cycle generating facility with a net generating capacity of 488 MW. As a result of Seminole's construction of HPS #3 and pursuant to the Seminole Agreement, adjustments must be made to the rates paid by Tampa Electric and Seminole to reflect Seminole's increased use of certain common facilities.[13] Accordingly, the Third Amendments reallocate the costs of the HPS Site Common Facilities and the costs of operating and maintaining those common facilities between Tampa Electric and Seminole. This reallocation is described further below.

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[12] These exceptions include liquidated damage provisions and the scheduling of planned outages, among others. The exceptions are described in full in Exhibit C, Tab 1 of the January 18 Application.

[13] HPS Plant Common Facilities are defined in the Fourth Amendments, and HPS Site Common Facilities are defined in the Third Amendments. HPS Plant Common Facilities are certain specified facilities within the Hardee Power Station such as the control building, the fire protection system, and the service water system. See footnote 3 for a description of HPS Site Common Facilities. The construction of HPS #3 will result in the increased utilization of HPS Site Common Facilities by Seminole, but will have no impact on the parties' utilization of HPS Plant Common Facilities.

VII. THIRD AMENDMENTS TO THE POWER SALES AGREEMENTS

A. Third Amendment to the Seminole Agreement

The Third Amendment to the Seminole Agreement addresses the reallocation of the costs of the HPS Site Common Facilities as a result of Seminole's construction of the Payne Creek Generating Station. Two different kinds of costs are involved: the actual costs of the common facilities and the fixed and variable costs of operating and maintaining those common facilities.

First, the actual costs of the common facilities themselves are reallocated and recovered through an adjustment to the Monthly Capacity Charge. Once Seminole receives the necessary approval from the State of Florida Department of Environmental Protection ("FDEP") for construction, the costs of the HPS Site Common Facilities must be reallocated to reflect Seminole's increased utilization of those facilities. This is accomplished through the HPS Site Common Facilities Capacity Charge Adjustment.[14] Through that adjustment, Seminole will pay a monthly charge of $25,168 in addition to its Monthly CT/CC Capacity Charge to reflect its increased utilization of the HPS Site Common Facilities. Effective January 1, 2003, that monthly charge will increase to $26,234 as a result of other rate adjustments previously set forth in the Seminole Agreement.

The fixed and variable operation and maintenance costs of the HPS Site Common Facilities are recovered through the Monthly Energy Charge. The existing Agreement is amended to make clear that the original 60%/40% allocation of operating and maintenance costs, other than the costs of operating and maintaining the HPS Site Common Facilities, is not changed by the Third Amendment. Three hundred and thirty days after the release of construction under the construction contract for the Payne Creek Generation Station, the fixed

[14] Third Amendment to the Seminole Agreement § 6.4.9.

operation and maintenance costs of the HPS Site Common Facilities costs are allocated 72% to Seminole and 28% to Tampa Electric. The reallocation of the variable operation and maintenance costs of the HPS Site Common Facilities takes place on the same effective dates described above.

Seminole will be allocated a pro-rata share of the variable operation and maintenance costs of the HPS Site Common Facilities based on the percentage of energy produced from the Hardee Power Station and the Payne Creek Generating Station as a proportion of the total energy produced from those same facilities during the previous twelve months.[15]

B. Third Amendment to the Tampa Electric Agreement

The Third Amendment to the Tampa Electric Agreement contains similar provisions to those described above with respect to the reallocation of the costs of the HPS Site Common Facilities as well as the fixed and variable operations and maintenance costs of those Common Facilities resulting from Seminole's construction of the Payne Creek Generating Station. Tampa Electric will receive a credit reducing the amount it owes through the Monthly CT/CC Capacity Charge to reflect Tampa Electric's relative decrease in its utilization of the HPS Site Common Facilities. Once Seminole receives the necessary approval for construction from the FDEP, Tampa Electric will receive a credit of $19,494 towards its Monthly CT/CC Capacity Charge.[16] Effective January 1, 2003, that credit increases to $20,320, as a result of other rate adjustments

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[15] For clarification, please note that the definition of Hardee Power Station within the Third Amendments differs from that used in this Petition. In the Amendments, Hardee Power Station is defined to include the Payne Creek Generating Station and the 2003 Capacity Additions (discussed in the Fourth Amendments), to the extent they are constructed, in addition to the facilities identified in footnote 5, above.

[16] Seminole's increase to its monthly charge is greater than Tampa Electric's credit because Seminole has agreed to pay the costs of certain facilities that where previously paid for by HPP. These facilities consist of a water well, pump, and a cooling reservoir and were constructed in anticipation of the addition of the Payne Street Generating Facility to the Site.

previously set forth in the Tampa Electric Agreement. In addition, the percentage of fixed and variable operation and maintenance costs paid by Tampa Electric will be reduced.

VIII. THE RATES UNDER THE THIRD AMENDMENTS TO THE POWER SALES AGREEMENTS SHOULD BE ACCEPTED BY THE COMMISSION

The rates under the Third Amendments to the Seminole and the Tampa Electric Agreements are just and reasonable. The changes in rates required by the Third Amendments implement provisions of the Seminole and Tampa Electric Agreements previously accepted by the Commission.[17] The rates under the Third Amendments are designed to reflect the increased usage by Seminole of certain HPS Site Common Facilities resulting from Seminole's decision to construct the Payne Creek Generating Station on the Site. Correspondingly, Tampa Electric's rates will decrease as a result of this reallocation, as discussed above. The rate adjustments implemented by the Third Amendments equitably reallocate the costs of the common facilities and, therefore, are just and reasonable. Both Seminole and Tampa Electric are in agreement with respect to the changes effected by the Third Amendments to both Agreements, as attested by the attached Letters of Concurrence (Exhibit B).

IX. REQUEST FOR WAIVERS

HPP requests the following waivers and preapprovals previously granted to single-asset utilities similar to HPP:

(a) waiver of the accounting and other requirements of Parts 41, 101, and 141 of the Commission's regulations;

(b) waiver of Part 45 of the Commission's regulations regarding interlocks, provided that HPP files abbreviated statements thereunder;

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[17] TECO Power Services Corporation, 53 FERC ¶ 61,202.

(c) waiver of Subparts B and C of Part 35 of the Commission's regulations as to this filing, except sections 35.13(b), 35.15 and 35.16; and

(d) blanket authorization of all future issuances of securities and assumptions of liabilities.

While these waivers for the Seminole and Tampa Electric Agreements were originally denied by the Commission,[18] the Commission has recently approved these waivers in a proceeding with factual circumstances similar to those described herein. The Commission concluded in Nevada Sun-Peak Limited Partnership that single asset utilities with long-term fixed rate contracts do not need to be subjected "to the full measure of [the Commission's] traditional regulatory requirements."[19] Likewise, HPP, as a single asset utility with long-term contracts in place, should not be subject to these regulatory requirements. Therefore, the above-listed waivers should be granted.

Furthermore, HPP requests a waiver of the 60-day notice requirement in section 35.3 of the Commission's regulations so as to allow the Amendments to become effective on or before November 1, 1999. HPP also requests any other waiver of the Commission's regulations necessary to allow the Amendments to become effective on that date.

X. REQUEST FOR EXPEDITED TREATMENT

It is imperative that the regulatory review and approval of the Third Amendments be expedited so that Seminole can meet certain critical financing obligations and schedules associated with the construction of the Payne Creek Generating Station. In order for Seminole to meet these deadlines, HPP requests that the Commission approve the Third Amendments by November 1, 1999.

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[18] Id.

[19] Nevada Sun-Peak Limited Partnership, 86 FERC ¶ 61,243 at 61,874 (March 10, 1999).

XI. EXHIBITS

The following supporting exhibits are attached to this Petition:

Exhibit A: Amendments

Tab 1: Third Amendment to Power Sales Agreement between HPP and Seminole

Tab 2: Third Amendment to Power Sales Agreement between HPP and Tampa Electric

Exhibit B: Purchasing Utilities' Letters of Concurrence to Petition

Exhibit C: Parties served with a copy of this Petition

Exhibit D: Form of Notice

Exhibit E: Certificate of Service

XII. CONCLUSION

For the reasons stated above, Hardee Power Partners Limited respectfully requests that the Commission accept for filing the Third Amendments to the Seminole and Tampa Electric Agreements. In order to enable Seminole to arrange the necessary financing for the construction of the Payne Creek Generation Station, Hardee Power Partners Limited requests that the Commission act on this filing prior to the expiration of the 60-day period set forth in Section 205 of the Federal Power Act.

Respectfully submitted,

Robert L. Daileader, Jr.
Karen Georgenson Gach
Nixon Peabody LLP
One Thomas Circle, N.W.
Suite 700
Washington, D.C. 20005
(202) 457-5300

Dated: September 15, 1999

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

99 SEP 15 PM 4:48
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of:	)	
	)	**ER99- -000**
Hardee Power Partners Limited	)	

PETITION OF HARDEE POWER PARTNERS LIMITED FOR AN ORDER ACCEPTING RATES

I. INTRODUCTION

Pursuant to Rules 205 and 207 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.205 and 385.207 (1998), and Sections 35.12 and 35.13 of the Commission's Regulations, 18 C.F.R. §§ 35.12 and 35.13 (1998), Hardee Power Partners Limited ("HPP") submits this abbreviated rate filing in connection with amendments to two power sales agreements ("Fourth Amendments" or "Amendments") providing for the sale by HPP of electric capacity and associated energy to Seminole Electric Cooperative, Inc. ("Seminole") and Tampa Electric Company ("Tampa Electric") from the Hardee Power Station, the rates under which were previously accepted by the Commission.[1] The Amendments filed herein implement the provisions of the original agreements which contemplate the expansion of the Hardee Power Station[2] and reflect certain related changes in the rates, as provided for in the power sale agreements. Tampa Electric has

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[1] TECO Power Services Corporation, 53 FERC ¶ 61,202 (1990) ("November 19 Order").

[2] The Hardee Power Station provides 295 MW of generating capacity, consisting of a 220 MW combined cycle unit ("CC 1") and a 75 MW combustion turbine ("CT 2A"), and uses natural gas as its primary fuel and No. 2 fuel oil as a back-up fuel. In the Amendments, these facilities are referred to as the CT/CC Facilities.

exercised its option under the original power sales agreements to require that HPP expand the Hardee Power Station in two phases, the first phase of which is the subject of the instant Petition.[3] The rate changes effected by the Fourth Amendments are two-fold: (1) HPP's construction of the first phase of the 2003 Capacity Additions at the Hardee Power Station necessitates a reallocation of the costs of certain common facilities, namely the HPS Site Common Facilities and the HPS Plant Common Facilities[4] between Tampa Electric and Seminole and (2) the Fourth Amendment to the Tampa Electric Agreement sets forth the rates, terms and conditions pursuant to which HPP shall sell capacity and corresponding energy from the first phase of the 2003 Capacity Additions to Tampa Electric. In both cases, the rate changes filed herein will yield an overall reduction in the unit cost of electricity paid by Seminole and Tampa Electric compared to those rates currently on file with the Commission. As further described herein, HPP requests waiver of the Commission's 60-day notice requirement and an effective date of November 1, 1999.

Contemporaneously with the filing of this Petition, HPP is filing a second petition submitting amendments to the same two power sales agreements ("Third Amendments"). The Third Amendments implement those provisions of the power sales agreements that allow Seminole to construct its own generation, the Payne Creek Generating Station, on the same site

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[3] The expansion of the Hardee Power Station is referred to in the original power sales agreements as the 2003 Capacity Additions. The first phase of the 2003 Capacity Additions will involve the construction of a second combustion turbine (the "CT 2B") adjacent to the CT 2A. Tampa Electric also retains the right to require that HPP construct an additional steam turbine and two heat recovery steam generators to form a second combined cycle unit ("CC 2"). Tampa Electric Agreement § 10.2.1.

[4] The HPS Site Common Facilities are the access roads, the cooling reservoir, the natural gas pipeline, the switchyard, the water wells, and pumps and the Site itself (see infra footnote 5), all of which will be shared by the Hardee Power Station and the Payne Creek Generating Station. The HPS Plant Common Facilities are certain specified facilities within the Hardee Power Station such as the control building, the fire protection system, and the service water system. HPP's construction of the first phase of the 2003 Capacity Additions will necessitate a reallocation of the costs of both the HPS Site Common Facilities and the HPS Plant Common Facilities, as well as the fixed and variable operation and maintenance costs of both categories of common facilities.

("Site")[5] on which the Hardee Power Station is situated and which make related rate adjustments.[6]

II. COMMUNICATIONS

All service and correspondence concerning this Application should be addressed to:

Robert L. Daileader, Jr.
Karen Georgenson Gach
Nixon Peabody LLP
One Thomas Circle, N.W., Suite 700
Washington, D.C. 20005
(202) 457-5300

and

Linda A. Miller
Vice President
Hardee Power Partners Limited
702 North Franklin Street
Tampa, Florida 33602
(813) 228-1311

III. BACKGROUND

On January 18, 1990, Power Services, HPP's predecessor in interest, and Tampa Electric filed for approval of the rates under three power sales agreements in Docket No. ER90-164 ("January 18 Application"). The three agreements were (1) the Agreement for Sale and Purchase of Capacity and Energy between TECO Power Services Corporation and Seminole Electric Cooperative, Inc. (the "Seminole Agreement"); (2) the Agreement for Sale and Purchase of

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[5] The Site is a 465-acre parcel of land contiguous to the Tampa Electric service territory which has been leased by Acuera Corporation, a subsidiary of Seminole, to TECO Power Services Corporation ("Power Services"), HPP's predecessor in interest. See infra footnote 9 and accompanying text.

[6] Seminole's construction of the Payne Creek Generating Station will necessitate the reallocation of the cost of the HPS Site Common Facilities and the fixed and variable operation and maintenance costs of those facilities.

Capacity and Energy from the Hardee Power Station between TECO Power Services Corporation and Tampa Electric Company (the "Tampa Electric Agreement") ("collectively, the "Power Sales Agreements" or the "Agreements"); and (3) the Agreement for Sale and Purchase of Capacity and Energy from Big Bend Station Unit No. 4 ("BB4") between TECO Power Services Corporation and Tampa Electric Company (the "BB4 Agreement").[7] The Power Sales Agreements and the BB4 Agreement form an integrated transaction in which HPP (1) has constructed, owns, and operates the Hardee Power Station; (2) sells for twenty years capacity and energy produced by the Hardee Power Station to Seminole and Tampa Electric pursuant to the Seminole and Tampa Electric Agreements, respectively; and (3) purchases for ten years certain rights to 145 MW of capacity and energy from Tampa Electric for resale to Seminole pursuant to the BB4 Agreement. The agreements were initially developed in response to Seminole's 1988 request for proposals to provide 440 MW of back-up power to Seminole over a twenty-year period commencing January 1, 1993. These agreements were negotiated and finalized at the conclusion of that bidding program and represented at the time an innovative mix of new and existing generating capacity to meet the complementary capacity and energy needs of Seminole and Tampa Electric.

On November 19, 1990, the Commission accepted the three agreements for filing, finding that the costs of the Hardee Power Station, including the equity allowance, and the allocation of those costs between Seminole and Tampa Electric to be reasonable.[8] The Commission designated the three agreements as follows: (1) the Seminole Agreement was designated as

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[10] On November 2, 1992 in Docket Nos. ER93-109-000 and ER93-134-000 and on September 20, 1993 in Docket No. ER93-966, HPP filed to make certain adjustments to the Monthly Capacity Charge payable by Seminole and Tampa Electric, which resulted in a net decrease in the rates charged both purchasers. The Commission accepted these revised rates by orders issued on December 29, 1992 and November 12, 1993, respectively.

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The Monthly Energy Charge is the sum of the energy charges for BB4 ("Monthly BB4 Cost") and the Hardee Power Station (the sum of the "Monthly Combustion Turbine Cost" and the "Monthly Combined Cycle Cost"). The calculation of the Monthly Energy Charge is based upon Seminole's actual energy usage from both BB4 and the Hardee Power Station during each month. The Monthly BB4 Cost is based on Seminole's pro-rata share (based on actual energy

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[11] A full description of the Seminole and the Tampa Electric Agreements is provided in the January 18 Application.

[12] The Seminole Agreement (and the Tampa Electric Agreement, discussed below) sets forth in detail the allocation of risks between the parties for construction and operating performance of the Hardee Power Station. Please refer to the description of the Agreements in the January 18 Application.

[13] Seminole's Monthly CT/CC Capacity Charge is subject to a maximum 33% reduction based upon the actual performance of the Hardee Power Station both at initial operation and during ongoing operations. The Agreement also contains a formula to adjust the Monthly CT/CC Capacity Charge to account for certain events, such as whether (a) a change in financing rates or federal or state income tax rates occurs, (b) Seminole exercises its option to purchase capacity and energy from an expansion of the Hardee Power Station, or (c) any of certain specified contingencies occurs.

usage) of fuel costs, production, operation and maintenance expenses, and pre-established administrative and general expenses. The Monthly Combustion Turbine Cost and Monthly Combined Cycle Cost are designed to recover Seminole's pro-rata share (based upon actual energy usage) of fuel and variable operation and maintenance costs and 60% of (1) the cost of fixed operation and maintenance, (2) the cost of replaced property units, and (3) administrative and general expenses.

B. The Tampa Electric Agreement

The Tampa Electric Agreement contains the terms and conditions of HPP's sale to Tampa Electric of an entitlement to 295 MW of capacity and associated energy from the Hardee Power Station for a twenty-year period commencing on January 1, 1993, with a potential expansion of such facilities to 440 MW for the final ten years of the contract term. The capacity and energy is utilized by Tampa Electric to meet its peaking power requirements. Tampa Electric is entitled to the capacity at any time to meet its native load or firm power commitments except to the extent that it is being utilized by Seminole to meet its back-up power requirements. The pricing of capacity and energy from the Hardee Power Station sold by HPP to Tampa Electric mirrors the provisions of the Seminole Agreement described above, except that Tampa Electric is allocated 40% of (1) the cost of fixed operation and maintenance, (2) the cost of replaced property units, and (3) administrative and general expenses through the monthly energy charge. Tampa Electric also pays a pro-rata share (based upon actual energy usage) of fuel and variable operation and maintenance costs.

With respect to non-rate terms and conditions, the Tampa Electric Agreement essentially mirrors the Seminole Agreement, with certain limited exceptions.[14]

VI. EXERCISE OF OPTION UNDER THE POWER SALES AGREEMENTS

The Seminole Agreement and the Tampa Electric Agreement provide both purchasers with certain rights to require HPP to expand the Hardee Power Station by the year 2003. This expansion (referred to in the Agreements as the "2003 Capacity Additions") can consist of a 75 MW second combustion turbine (the "CT 2B"), two heat recovery steam generators, and one 70 MW steam turbine which, when fully constructed, would provide a second combined cycle unit with a total capacity of 220 MW.[15] Under the original Agreements, the right to require the construction of the 2003 Capacity Additions was given first to Seminole, then to HPP, and, finally, to Tampa Electric. Seminole and HPP have determined not to exercise the option. Tampa Electric has decided to exercise its option under the Tampa Electric Agreement, as described below.

Tampa Electric has exercised its option to require that HPP construct the 2003 Capacity Additions in two phases. The first phase consists of a single combustion turbine, the CT 2B, of approximately 75 MW net capacity and is scheduled to be in service by May 15, 2000. Tampa Electric retains an option to require HPP to construct the second phase consisting of the remainder of the facilities (two heat-recovery steam generators and one 70 MW steam turbine).

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[14] These exceptions include liquidated damage provisions and the scheduling of planned outages, among others. The exceptions are described in full in Exhibit C, Tab 1 of the January 18 Application.

[15] Thus, construction of the 2003 Capacity Additions would result in the Hardee Power Station consisting to two 220 MW combined cycle units ("CC 1" and "CC 2").

To exercise its remaining option, Tampa Electric must provide written notice to HPP prior to December 1, 2000.[16]

The purpose of the Fourth Amendments to the Power Sales Agreements is three-fold. First, the Amendments continue the reallocation, as between Tampa Electric and Seminole, of the costs of the HPS Site Common Facilities and the costs of operating and maintaining those common facilities as a result of Seminole's construction of the Payne Creek Generating Station implemented by the Third Amendments.[17] This reallocation is further explained in the Third Amendments and the corresponding petition. Second, the Fourth Amendments reallocate the costs of the HPS Plant Common Facilities and the HPS Site Common Facilities and the costs of operating and maintaining both categories of common facilities between Tampa Electric and Seminole as a result of HPP's construction of the first phase of the 2003 Capacity Additions on behalf of Tampa Electric.[18] Third, the Tampa Electric Agreement is amended to provide for the sale of capacity and associated energy by HPP to Tampa Electric from the first phase of the 2003 Capacity Additions as well as other terms and conditions associated with the construction of that new capacity, including performance guarantees.

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16 See Fourth Amendment to the Tampa Electric Agreement § 10.2.1.

17 While declining its option relating to the 2003 Capacity Additions, Seminole has exercised its right under Section 7.6 of the Seminole Agreement to construct its own combined cycle generating facility adjacent to the Hardee Power Station on the same Site. The Seminole project is referred to as the Payne Creek Generating Station or Hardee Power Station, Unit No. 3 ("HPS #3"). This facility will have a net generating capacity of 488 MW, rather than 220 MW as provided in the Seminole Agreement. As a result of Seminole's construction of the Payne Creek Generating Station and pursuant to the Seminole Agreement, adjustments have been made to the rates paid by Tampa Electric and Seminole to reflect Seminole's increased use of certain common facilities defined within the Third Amendments. The Third Amendments, filed contemporaneously with this Petition, implement these rate adjustments, and the Fourth Amendments continue those adjustments.

18 Since the 2003 Capacity Additions will utilize common facilities within the Hardee Power Station itself (such as the fire protection system, the control building, and the sewage treatment/wastewater system) as well as common facilities not physically within the Hardee Power Station but on the same site (such as access roads, the cooling reservoir and the switchyard), Tampa Electric will contribute to both the HPS Plant Common Facilities and the HPS Site Common Facilities. In contrast, Seminole's Payne Creek Generating Station will utilize only HPS Site Common Facilities. For that reason, the rate adjustments resulting from Seminole's

(Footnote continued on next page)

VII. FOURTH AMENDMENTS TO THE POWER SALES AGREEMENTS

A. Fourth Amendment to the Seminole Agreement

The Fourth Amendment to the Seminole Agreement addresses the reallocation of the costs of the HPS Site Common Facilities and the HPS Plant Common Facilities as a result of HPP's construction of the 2003 Capacity Additions for the benefit of Tampa Electric. In addition, the Fourth Amendment continues the reallocation of HPS Site Common Facilities implemented by the Third Amendment as a result of Seminole's decision to construct the Payne Creek Generating Station. The allocation of two different kinds of costs are involved: the actual costs of the common facilities and the fixed and variable costs of operating and maintaining the common facilities.

First, the actual costs of the HPS Site Common Facilities and the HPS Plant Common Facilities are reallocated and recovered through an adjustment to the Monthly Capacity Charge, referred to in both Fourth Amendments as the "HPS Shared Common Facilities Capacity Charge Adjustment." This adjustment is phased in over time as both Seminole and HPP obtain the necessary regulatory approvals to construct the Payne Creek Generating Station and the first phase of the 2003 Capacity Additions, respectively. At present, it is anticipated that Seminole will be the first to receive the necessary approval from the State of Florida Department of Environmental Protection ("FDEP"), resulting in the reallocation of costs of the HPS Site Common Facilities to reflect Seminole's increased utilization of those facilities. Thus, Seminole will initially pay a monthly charge of $25,168 in addition to its Monthly CT/CC Capacity

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(Footnote continued from previous page)

construction of the Payne Creek Generating Station made in the Third Amendments and continued in the Fourth Amendments only adjust the charges related to the HPS Site Common Facilities.

Charge.[19] Following the date when HPP receives approval from the FDEP to construct the first phase of the 2003 Capacity Additions, a reallocation of the costs of both the HPS Site Common Facilities and the HPS Plant Common Facilities will result in a credit to Seminole in the amount of $51,657 per month against the Monthly CT/CC Capacity Charge. Commencing on January 1, 2003, the monthly credit to Seminole will increase to $53,845 as a result of other rate adjustments previously set forth in the Seminole Agreement. The Fourth Amendment to the Seminole Agreement addresses the possibility that the sequencing of regulatory approvals may be different from what the parties now contemplate and would require a recalculation of the charges/credits described above to account for the re-sequencing of the regulatory approvals.

The fixed and variable operation and maintenance costs of the HPS Site Common Facilities and the HPS Plant Common Facilities are recovered through the Monthly Energy Charge. First, the existing Seminole Agreement is amended to make clear that the original 60%/40% allocation of costs other than the costs of the HPS Site Common Facilities and the HPS Plant common facilities are not changed by the Fourth Amendment. The reallocation of the fixed operation and maintenance costs of both the HPS Site Common Facilities and the HPS Plant Common Facilities are triggered by different effective dates. First, ninety days after the release of construction under the construction contract for the first phase of the 2003 Capacity Additions, the fixed operation and maintenance costs of the HPS Site Common Facilities are allocated 46.8% to Seminole and 53.2% to Tampa Electric. Three hundred and thirty days after the release of construction under the construction contract for the Payne Creek Generating Station, the same fixed costs are allocated 62.2% to Seminole and 37.8% to Tampa Electric. The

[19] The additional charges to Seminole resulting from its increased use of HPS Site Common Facilities is described in detail in the Third Amendment to the Seminole Agreement and related petition.

fixed operation and maintenance costs of the HPS Plant Common Facilities are allocated 40.2% to Seminole and 59.8% to Tampa Electric beginning on the date which is ninety days after the release of construction under the construction contract for the first phase of the 2003 Capacity Additions.

The reallocation of the variable operation and maintenance costs of the HPS Site Common Facilities and the HPS Plant Common Facilities takes place on the same effective dates described above. The reallocation of the variable costs for the HPS Site Common Facilities will be calculated on a monthly basis and will be done based on the energy taken by Seminole and Tampa Electric over the prior twelve-month period as a percentage of the total energy produced by all generation at the Site (i.e., the Hardee Power Station plus the Payne Creek Generating Station) over the same period.[20] The reallocation of the variable costs of the HPS Plant Common Facilities will be calculated based on energy taken by Seminole from the Hardee Power Station and by Tampa Electric from both the Hardee Power Station and the first phase of the 2003 Capacity Additions over the prior twelve months as a percentage of the total energy produced by the Hardee Power Station and the first phase of the 2003 Capacity Additions over the same period. Fuel costs continue to be allocated on a pro-rata basis according to Seminole's actual usage.

B. Fourth Amendment to the Tampa Electric Agreement

The Fourth Amendment to the Tampa Electric Agreement contains similar provisions to those described above with respect to the reallocation of the costs of the HPS Site Common Facilities and the HPS Plant Common Facilities as well as the fixed and variable operations and

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[20] For clarification, please note that the definition of Hardee Power Station within the Third and Fourth Amendments differs from that used in this Petition. In the Third Amendments, Hardee Power Station is defined to include the Payne Creek Generating Station and the 2003 Capacity Additions, to the extent they are constructed, in addition to the facilities identified in footnote 2, supra.

maintenance costs of those common facilities. In addition, the Fourth Amendment to the Tampa Electric Agreement contains additional rates, terms, and conditions addressing the sale of the capacity and associated energy by HPP to Tampa Electric from the first phase of the 2003 Capacity Additions.

VIII. THE RATES UNDER THE FOURTH AMENDMENTS TO THE POWER SALES AGREEMENTS SHOULD BE ACCEPTED BY THE COMMISSION

A. The Rates Under the Fourth Amendment to the Seminole Agreement Should be Accepted by the Commission

The Fourth Amendment to the Seminole Agreement alters the rates paid by Seminole to reflect the change in the allocation of the costs of the HPS Site Common Facilities and HPS Plant Common Facilities necessitated by HPP's construction of the 2003 Capacity Expansion on behalf of Tampa Electric. The Fourth Amendment also continues the reallocation of the costs associated with HPS Site Common Facilities implemented in the Third Amendments to reflect Seminole's increased usage of those facilities as a result of Seminole's construction of the Payne Creek Generating Station. The reallocation required by HPP's construction of the first phase of the 2003 Capacity Additions will shift costs away from Seminole and will result in a monthly credit, upon certain effective dates described above, reducing Seminole's Monthly CT/CC Capacity Charge. These revised rates equitably allocate the costs associated with the facilities and should, therefore, be accepted by the Commission. HPP, Seminole, and Tampa Electric are in agreement with respect to the allocation of these costs between Seminole and Tampa Electric.

B. The Rates Under the Fourth Amendment to the Tampa Electric Agreement Should be Accepted by the Commission

The Commission should accept the rates under the Fourth Amendment as just and reasonable.[21] This Amendment merely implements the provisions of the Power Sales Agreements, previously accepted by the Commission, which specifically contemplate the construction of the 2003 Capacity Additions. The energy and capacity being sold to Tampa Electric from the first phase of the 2003 Capacity Additions is being sold at rates lower than the rates established in the Tampa Electric Agreement for the currently existing capacity. The capacity rates for the existing capacity remains unchanged, except for costs related to the reallocation of the costs of common facilities, described above.

The Commission should conclude that the rates paid by Tampa Electric for the capacity produced by the first phase of the 2003 Capacity Additions are just and reasonable. First, the construction of those facilities is expressly provided for in the Seminole and Tampa Electric Agreements, both of which were accepted for filing by the Commission in Docket No. ER90-164-001. In addition, it is clear that the rates for capacity paid by Tampa Electric for the first phase of the 2003 Capacity Additions are significantly lower than the rates paid for the remaining capacity supplied by the Hardee Power Station. Exhibit D, attached hereto, provides a comparison of the capacity rates. The capacity rate for the first phase of the 2003 Capacity Additions is $6.02 per kW per month, compared to the average rate of $9.33 per kW per month paid by Seminole and Tampa Electric for the 295 MW produced by the Hardee Power Station, a rate reduction of more than 35%. Exhibit C, also attached hereto, contains detailed financial

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[21] This section addresses the capacity rates under the Fourth Amendment to the Tampa Electric Agreement. Fuel costs and variable operation and maintenance costs continue to be allocated based upon actual usage through the monthly energy charge. Fixed operation and maintenance costs are allocated as described above in Section VII.A.

projections relating to the operation of the first phase of the 2003 Capacity Additions from the projected in-service date of May 15, 2000 until the end of the term of the Tampa Electric Agreement on December 31, 2012. Included in Exhibit C is a Summary of Financial Information (Tab 1), an Income Statement (Tab 2), a Cash Flow Schedule (Tab 3). and a Revenue Requirement Calculation (Tab 5).[22]

The components of the capacity rate paid by Tampa Electric for the first phase of the 2003 Capacity Additions can also be shown to be just and reasonable in relation to the rates found to be just and reasonable by the Commission in Docket No. ER90-164-001. For example, HPP's investment base in the first phase of the 2003 Capacity Additions is projected to be [**Privileged Information --** [redacted] of which [redacted] (or [redacted] of the total investment)] will be paid to the construction contractor, National Energy Production Corporation, an unaffiliated entity. In Docket No. ER90-164-001, the Commission determined that Power Services' $195 million investment base in the Hardee Power Station to be reasonable, particularly in light of the fact that 85% of the investment base reflected a known payment to the turnkey contractor.[23] Thus, consistent with its determination in Docket No. ER90-164-001, the Commission should find HPP's investment base in the first phase of the 2003 Capacity Additions to be just and reasonable.

Furthermore, the capital structure for the first phase of the 2003 Capacity Additions is projected to be 80% debt and 20% equity, substantially the same capital structure reviewed and approved by the Commission in Docket No. ER90-164-001 for the Hardee Power Station (77.5%

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22 HPP has provided this data in substantially the form of the cost-of-service data submitted by Power Services and accepted for filing by the Commission in Docket No. ER90-164-001. See Petition for Rehearing, Tab C, Affidavit of Mark D. Luftig.

23 TECO Power Services Corporation, 53 FERC ¶ 61,202 at 61,811.

debt and 22.5% equity).[24] The long-term debt for the first phase of the 2003 Capacity Additions is expected to be financed for a twenty year term with coverage ratios averaging 1.41. This is an aggressive financing plan since the debt term exceeds the remaining contract term by eight years. However, twenty-year financing permits the project to be leveraged up to 80% which, in turn, allows HPP to structure just and reasonable capacity rates while providing HPP with a reasonable return. The interest rate is assumed to be 7.5% which is substantially lower than the assumed 10.5% long-term finance rate used for the financing of the Hardee Power Station[25] as well as the actual "all-in" rate that HPP was ultimately able to lock into through the issuance of secured facility bonds.[26] Finally, HPP projects an internal rate of return of **[Privileged Information --** [redacted] for the first phase of the 2003 Capacity Additions over the remaining term of the Tampa Electric Agreement. In Docket No. ER90-164-001, the Commission approved a projected internal rate of return equal to 20.13% over the useful life of the Hardee Power Station (30 years). The above comparisons demonstrate that the capital structure, cost of long-term debt, and the internal rate of return for the first phase of the 2003 Capacity Additions are reasonable.

The Commission, in Docket No. ER90-164-001, corroborated the reasonableness of the rates paid by Tampa Electric and Seminole under the Power Sales Agreements by comparing those rates to the rates Tampa Electric could have charged if it had undertaken to construct the generating facilities on its own. The Commission engaged in this analysis because it could not "derive the precise rate of return equity investors would demand for this project because Power

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[24] Id. at 61,811, n. 17.

[25] See Tampa Electric Agreement § 6.4.1; Seminole Agreement § 6.4.1.

[26] See Application for Change in Rates filed November 2, 1992 in Docket No. ER90-164-003. The "all-in" rate is the rate based on the coupon rate plus a yield needed to recover applicable transaction costs.

Services, as a wholly owned subsidiary of TECO Energy, will issue no publicly available common stock for which a discounted cash flow ('DCF') cost of common equity could be calculated."[27] Because HPP has not issued publicly available common stock, HPP has completed an analysis of the financing of the first phase of the 2003 Capacity Additions as if those additions were constructed and owned by Tampa Electric. In order to compare the rates charged by HPP to traditional cost-based rates, HPP has prepared a simple revenue requirements model set forth as Exhibit C, Tab 5. In this model, the capital structure consists of 37.2% debt (with a pre-tax rate of 7.0%) and 62.8% equity. These figures are equal to Tampa Electric's capital structure and average costs of borrowing as of December 31, 1998. In addition, this model utilizes a 11.75% cost of equity which is Tampa Electric's current midpoint return on equity allowed by the FPSC. This capital structure results in an overall weighted cost of capital of 9.98%.

In this model, the average rate base is multiplied by the weighted cost of capital to derive the allowed return on rate base. The allowed return on rate base is then grossed up for income taxes and increased by property taxes, insurance, administrative and general expenses, and depreciation to derive the revenue requirement in each year. Since fuel expenses and operation and maintenance expenses are not recovered through the capacity payment, they are not included in this model. The present value of the revenue requirements through the year 2012 is $50.042,000 using a 9.98% discount rate or $7,099,000 on an annual levelized basis. The present value of the capacity charges to be paid by Tampa Electric to HPP for the capacity from the first phase of the 2003 Capacity Additions using the same discount rate and term is $38,195,000, which is equivalent to a levelized annual payment of $5,419,000. Thus, Tampa

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[27] TECO Power Services Corporation, 53 FERC ¶ 61,202 at 61,811.

Electric's levelized payment to HPP is in excess of twenty percent lower than the revenue requirements associated with traditional utility financing and rate base treatment.

This analysis, therefore, demonstrates that the rates for the capacity from the first phase of the 2003 Capacity Additions are reasonable when compared to revenue requirements conventionally calculated on the basis of Tampa Electric's capital structure, an appropriate interest rate, and an equity return rate based on Tampa Electric's currently allowable equity return. In fact, use of Tampa Electric's midpoint allowed equity return significantly understates the cost of capital because the Hardee Power Station has significantly higher financial and business risks than a typical, utility-owned unit.

As the Commission is well aware, independent power projects have a unique set of financial risks which influence what rate of return is reasonable. Independent power projects are normally financed as stand-alone entities. As such, the risks borne by the investors are greatest through construction and start-up, during which time investors are generally at risk that the project will not be completed on time, on budget, or in accordance with specified performance standards set forth in the relevant power contract. It is significant that during this phase there are no project revenues. Only after the project is operating at contracted levels will payments begin. This difference between the time when risks are incurred and when returns are generated requires that returns be evaluated at the outset for the total life of the project. The lenders look only to the cash flows and debt service coverage ratios of the project in analyzing the debt repayment stream. The equity investors also look exclusively to the cash flows of the project for their equity returns since all available cash, after payment of expenses and debt service, is distributed to the project's equity participants. Accordingly, projects are normally evaluated by equity investors in terms of an overall project internal rate of return. The internal rate of return measures the percentage rate at which the present value of the expected series of cash flows

recovers the initial equity invested. Given the risk inherent in an independent power project, HPP's projected internal rate of return is reasonable.

In addition, the Commission's approval of the rates contained in the Fourth Amendment to the Tampa Electric Agreement is consistent with the Commission's recent order in Nevada Sun-Peak Limited Partnership.[28] Like HPP, Nevada Sun-Peak is a single asset utility with a long-term power purchase agreement accepted by the Commission as a cost-based rate schedule. On December 21, 1998, Nevada Sun-Peak filed an amendment to that agreement that, among other things, increased the output of Nevada Sun-Peak's generating station. The capacity rates for the additional capacity represented a significant decrease from the rates applicable to the existing capacity. While the Commission denied Nevada Sun-Peak's request for market-based rates, the Commission did accept the amended power sales agreement as a stand-alone rate schedule. The Commission cited the lower rates for the additional capacity as justification for accepting the amended power sales agreement. It is noteworthy that the Commission did not require that Nevada Sun-Peak file cost-of-service data in accepting the agreement for filing.

The same reasoning should apply to the Fourth Amendment of the Tampa Electric Agreement filed in the instant proceeding. As discussed above, the expansion of the Hardee Power Station was expressly provided for in the Agreements accepted for filing by the Commission in Docket No. 90-164-001, and the unit capacity rate for the capacity added through the first phase of the 2003 Capacity Additions is significantly less than the rates determined by the Commission to be just and reasonable in the earlier proceeding. In addition, HPP has provided substantial cost-of-service data in support of this filing, more than was necessary in the

[28] 86 FERC ¶ 61,243 (March 10, 1999) ("Nevada Sun-Peak").

recent Nevada Sun-Peak order. Therefore, consistent with Commission precedent, the Commission should accept these rates for filing.

IX. REQUEST FOR PRIVILEGED TREATMENT

Pursuant to Section 388.112 of the Commission's regulations,[29] HPP requests that portions of this Petition and the attached exhibits submitted herein be withheld from public disclosure. The portions to which this request relates have been marked in this Petition and have been indicated on the Exhibits with heavy brackets in the original of this filing and have been redacted from each of the copies of the filing submitted to the Commission. These portions deal with the costs that HPP incurs and the financial obligations it will assume with respect to the construction and the financing of the first phase of the 2003 Capacity Additions. This information is proprietary in nature and, if publicly disclosed, could cause competitive harm to HPP. Hence, this information is exempt from mandatory public disclosure under exemption (4) to the Freedom of Information Act.[30]

X. REQUEST FOR WAIVERS

HPP requests the following waivers and preapprovals previously granted to single-asset utilities similar to HPP:

(a) waiver of the accounting and other requirements of Parts 41, 101, and 141 of the Commission's regulations;

(b) waiver of Part 45 of the Commission's regulations regarding interlocks, provided that HPP files abbreviated statements thereunder;

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[29] 18 C.F.R. § 112 (1998).

[30] 5 U.S.C. § 552(b)(4).

(c) waiver of Subparts B and C of Part 35 of the Commission's regulations as to this filing, except sections 35.13(b), 35.15 and 35.16; and

(d) blanket authorization of all future issuances of securities and assumptions of liabilities.

While these waivers for the Power Sales Agreements were originally denied by the Commission,[31] the Commission has recently approved these waivers in a proceeding with factual circumstances similar to those described herein. The Commission concluded in Nevada Sun-Peak that single asset utilities with fixed rate contracts do not need to be subjected "to the full measure of [the Commission's] traditional regulatory requirements."[32] Likewise, HPP, as a single asset utility with long-term contracts in place, should not be subject to these regulatory requirements. Therefore, the above-listed waivers should be granted.

Furthermore, HPP requests a waiver of the 60-day notice requirement in section 35.3 of the Commission's regulations to allow the Amendments to become effective on or before November 1, 1999. HPP also requests any other waiver of the Commission's regulations necessary to allow the Amendments to become effective on that date.

XI. REQUEST FOR EXPEDITED TREATMENT

It is imperative that the regulatory review and approval of the Fourth Amendments be expedited so that Tampa Electric may meet the electrical demands of its customers. Tampa Electric requires additional generating capacity by the summer of 2000 in order to serve its customers. If this demand is not met, Tampa Electric's customers could experience increased electricity prices resulting from the company's purchase of incremental power from other

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31 TECO Power Services, Corporation, 53 FERC ¶ 61,202.

32 Nevada Sun-Peak Limited Partnership, 86 FERC ¶ 61,243 at 61,874.

sources. Accordingly, Tampa Electric has requested that HPP accomplish an in-service date of May 15, 2000 to satisfy the anticipated energy demands of Tampa Electric's customers. This timeframe requires that the construction contractor be released for site construction activities by November 15, 1999. Presently, HPP has located generating equipment which can be placed into service by May 15, 2000 and meet Tampa Electric's capacity need, provided that the necessary regulatory approvals are granted in a timely manner.

Furthermore, the loan documents related to the existing HHP assets require that a number of items be delivered to the lenders before any new construction at the Site can commence, and Commission approvals are an integral component of satisfying the completion of such items. An expedited Commission review would ensure adequate time between the approval date and construction start date for all the necessary documentation to be filed with and reviewed by the lenders.

For these reasons, HPP requests that the Commission approve the Fourth Amendments by November 1, 1999.

XII. EXHIBITS

The following supporting exhibits are attached to this Petition:

Exhibit A: Amendments

- Tab 1: Fourth Amendment to Power Sales Agreement between HPP and Seminole
- Tab 2: Fourth Amendment to Power Sales Agreement between HPP and Tampa Electric

Exhibit B: Diagram of the Hardee Power Station, including the 2003 Capacity Additions

Exhibit C: Cost Support for Rates under the Fourth Amendment to the Tampa Electric Agreement

Tab 1: Summary of Financial Information **[Contains Privileged Information]**

Tab 2: Income Statement **[Contains Privileged Information]**

Tab 3: Projected Cash Flow **[Contains Privileged Information]**

Tab 4: Projected Capital Costs **[Contains Privileged Information]**

Tab 5: Revenue Requirement Model **[Contains Privileged Information]**.

Exhibit D: Rate Comparison Between Existing Facilities and First Phase of the 2003 Capacity Additions **[Contains Privileged Information]**

Exhibit E: Purchasing Utilities' Letters of Concurrence to Petition

Exhibit F: Parties served with a copy of this Petition

Exhibit G: Form of Notice

Exhibit H: Certificate of Service

XIII. CONCLUSION

For the reasons stated above, Hardee Power Partners Limited respectfully requests that the Commission accept the rates filed herein as stated in the Fourth Amendments to the Seminole and Tampa Electric Agreements. In order to enable HPP to arrange the necessary financing for

the construction of the first phase of the 2003 Capacity Additions, Hardee Power Partners Limited requests that the Commission act on this filing prior to the expiration of the 60-day period set forth in Section 205 of the Federal Power Act.

Respectfully submitted,

Robert L. Daileader, Jr.
Karen Georgenson Gach
Nixon Peabody LLP
One Thomas Circle, N.W.
Suite 700
Washington, D.C. 20005
(202) 457-5300

Dated: September 15, 1999

EXHIBIT NO. 35
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MDW-1)
DOCUMENT NO. 1
PAGE 1 OF 2

TAMPA ELECTRIC COMI
DOCKET NO. 990001-EI
STAFF'S 2nd SET OF INTE
INTERROGATORY NO. 26
PAGE 1 of 2
REVISED: 8/19/99

26. Please indicate for each unit the incremental fuel costs associated with replacing the unavailable energy from Gannon Units 1 through 6 with other TECO generating units.

A. An estimated of the incremental fuel and purchased power expense is provided in the attached table. This estimate compared actual fuel and purchased power expenses to that estimated using actual hourly load data and outage data for non-Gannon Units. For the estimated case in which the Gannon accident did not occur, the Gannon Unit outages were assumed to be what was planned prior to the Gannon Unit 6 accident. The analysis was conducted for the period of April through June of 1999. Other planning assumptions used in the analysis were identical to those used in Tampa Electric's 1999 fuel adjustment filing and were not adjusted to reflect actual conditions.

Tampa Electric has initiated a study that will benchmark its system for the months of April, May and June of 1999. This study will use actual hourly load data, unit outage data, actual fuel and purchase power data and actual unit operating data for the study period. The results of this study will provide more precise results of the incremental fuel and purchase power expense that occurred as a result Gannon explosion. These results will be provided to the Commission and Staff.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 35
COMPANY/ WITNESS: Ward
DATE 11-22-99

INTERROGATORY NO. 26

April - June 1999

	(A) Estimated Replacement Energy (GWH)	(B) Estimated Capacity (MW)	(C) Estimated Fuel or Purchase Power Expense ($/MWH)	(D) Estimated Gannon Station Fuel Expense ($/MWH)	(E) Estimated Fuel Expense Differential ($/MWH)	(F) Estimated Incremental Fuel Expense ($000)
BIG BEND & GANNON CTS TOTAL	7.9	138	52.68	23.16	29.52	232.94
HOOKERS POINT STATION TOTAL	13.2	204	35.59	23.16	12.43	164.27
GANNON STATION TOTAL	143.9	1095	24.13	23.16	0.97	139.58
BIG BEND STATION TOTAL	0.0	1712	19.35	23.16	(3.81)	0.00
PHILLIPS STATION TOTAL	4.2	34	30.70	23.16	7.54	31.94
POLK UNIT 1 TOTAL	0.0	250	25.51	23.16	2.35	0.00
				Total Incremental Fuel Expense of Energy Replaced by Non-Gannon Generating Units		568.74
PURCHASES TOTAL	159.0		48.04	23.16	24.88	3,955.90
				Total Incremental Purchase Power Expense of Energy and Capacity Replaced by Purchase Power and Non-Gannon Generating Units		4,524.64
ESTIMATED UNAVAILABLE ENERGY DUE TO GANNON 6 ACCIDENT	(328.2)					
TOTAL FIRM ENERGY UNSERVED	0.0					

Note: Estimated purchase power expense cost includes energy and capacity costs.
Note: Incremental fuel expense is the product of estimated replacement energy and estimated fuel differential.
Note: The estimated Gannon fuel expense in col (C) reflects the weighted average of the Gannon units based on actual generation.
Note: The estimated Gannon fuel expense in col (D) reflects the weighted average of the units based on projected generation of the units.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 2nd SET OF INTERROGATORIES
INTERROGATORY NO. 26
PAGE 2 of 2
REVISED: 8/19/99

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MDW-1)
DOCUMENT NO.1
PAGE 2 OF 2

EXHIBIT NO. _____
DOCUMENT NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MDW-1)
DOCUMENT NO. 2

Total Fuel & Purchased Power Cost Due to the Gannon 6 Accident

	April	May	June	Total Cost
Incremental Fuel	(740,341)	(276,336)	(364,073)	(1,380,750)
Incremental Purchased Power	4,131,880	776,695	1,545,701	6,454,276
Total Cost	3,391,539	500,359	1,181,628	5,073,526

() denotes the cost of the non-accident case was higher than the accident case.

EXHIBIT NO. 36
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(MDW-2)
DOCUMENT NO. 1
PAGE 1 OF 1
FILED: 11/1/99

Cost Effectiveness Analysis

Resource Alternatives	
Base Case	3 year purchase power, (Summer 2000-Winter 2003)
Florida Power Corporation	Summer 2000-2012
Florida Power and Light	Summer 2000-2012
Hardee Power Station Purchase Power Agreement	Summer 2000-2012

Cumulative Present Worth Revenue Requirements
(99$000)

Resource Alternatives	2002	2012
Base Case	-	-
Florida Power Corporation	(7,270)	6,496
Florida Power and Light	(3,816)	5,387
Hardee Power Station Purchase Power Agreement	(7,618)	(3,159)

Notes:
1) All costs/savings are incremental to the base case.
2) Negative values are savings. Positive values are costs.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 36
COMPANY/ Tampa Electric
WITNESS: M. Waters
DATE: 11-22-99

Summary of Teco's BuyThrough Activity

	(1)	(2)	(3)	(4)	(5)	(6)
					Col 4 Minus 3.8 cents	Col 3 Times Col 5
	Optional Purchase Volumes (Mwh)			Price Paid Cent/Kwh		
	Total	For Wholesale	For IS1 & IS3	Price Paid	Premium Vs 3.8 cent /Kwh "Norm"	Approximate Penalty Dollars $000
Aug 1997	21,708.2	819.3	20,888.9	5.02260	1.22260	$255
Jul 1998	17,773.1	432.1	17,341.0	7.32200	3.52200	$611
Aug	18,163.8	573.9	17,589.9	5.58670	1.78670	314
Sep	13,721.1	317.2	13,403.9	5.96500	2.16500	290
Oct	9,096.9	246.5	8,850.4	5.94290	2.14290	190
Nov	965.0	23.7	941.3	4.70580	0.90580	9
Dec	233.2	1.4	231.8	4.90000	1.10000	3
Jan 1999	879.6	9.9	869.7	13.49760	9.69760	84
Feb	0.0	0.0	0.0	0.00000	0.00000	0
Mar	0.0	0.0	0.0	0.00000	0.00000	0
Apr	35,475.2	788.3	34,686.9	8.76990	4.96990	1,724
May	15,429.7	654.3	14,775.4	5.52430	1.72430	255
Jun	26,653.8	889.3	25,764.5	4.41320	0.61320	158
Jul	25,529.2	963.9	24,565.3	13.49820	9.69820	**2,382**
Aug	47,459.6	1,909.8	45,549.8	14.98710	11.18710	**5,096**
			Total July and August 1999			**$7,478**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 37
COMPANY/ WITNESS: Ward
DATE: 11-22-99

9-30-99;11:25AM;MULBERRY CORP. SALES ;8414251086 # 2/ 26

Revisions to the testimony of Karen O. Zwolak – Docket No. 990001

Page No.	Line No.	Revision
8	13	Add the word "and" after "("CT")," Replace the comma after "agreement" and replace with a period Strike entire line
	14	
	15	
11	24-25	Strike both lines
12	1-22	Strike lines 1-22
13	5	Strike "$0.43" and replace with "$1.99"

Document KOZ-4 has been deleted from my exhibits

KENT D. TAYLOR
PROFESSIONAL QUALIFICATIONS

INDUSTRY EXPERIENCE

OCTOBER 1984 to PRESENT

Chairman, KTM, an energy management and consulting business specializing in the economic interests of large natural gas and electricity users.

JANUARY 1984 to OCTOBER 1984

Director of Gas Acquisitions, KN Energy, Inc. Responsible for natural gas supply for company's integrated pipeline system, operating in seven states. Other responsibilities included all liquids marketing, negotiation of transportation and exchange agreements, pursuit of additional markets, and gas sales agreements for affiliate exploration company.

APRIL 1981 to JANUARY 1984

Director of Corporate Development, Celeron Corporation. Responsible for new business development, acquisitions and mergers, strategy development for existing pipelines (Louisiana Intrastate Gas and Mid Louisiana Gas), and gas marketing for Rocky Mountain area exploration efforts.

AUGUST 1980 to APRIL 1981

Senior Sales Representative, Colorado Interstate Gas Company (CIG). Primary responsibility was new market development. Also negotiated industrial gas sales agreements.

APRIL 1978 to JULY 1980

Senior Staff Analyst, Special Projects, CIG. Responsibilities included formulation of negotiating strategies, initiation of new business opportunities and economic analyses for investment decisions.

JANUARY 1975 to AUGUST 1978

Senior Rate Analyst, CIG. All facets of interstate pipeline rate making.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 38
COMPANY/ WITNESS: Taylor
DATE 11-23-99

KENT D. TAYLOR
PROFESSIONAL QUALIFICATIONS

EDUCATION

BSBA, University of Florida, Gainesville, Florida
1967
Major: Accounting

MS, The George Washington University, Washington D.C.
1972
Major: Public Administration

MBA, University of Colorado, Colorado Springs
1979
Major: Accounting/Finance

U.S. Naval Flight Training
Designated U.S. Naval Aviator July 1969

Defense Resource Management Education Course, Navy
Postgraduate School, Monterey, California
1988

PROFESSIONAL QUALIFICATIONS

Certified Public Accountant
Captain, U.S. Naval Reserve (ret)

OTHER TESTIMONY

Regie Du Gaz Natural Du Quebec
Florida Public Service Commission
Colorado Public Utilities Commission
Public Service Commission of Nevada
Federal Energy Regulatory Commission

TESTIMONY OF DAVID P. WHEELER

Q. Would you please state your name and business address?

A. My name is David P. Wheeler; 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By whom are you employed and in what capacity?

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst in the Bureau of Electric Regulation, Division of Electric and Gas.

Q. Please give a brief description of your educational background and professional experience.

A. I graduated from the University of Kansas in 1982 with a Bachelor of Science Degree in Business Administration. In 1984 I was awarded a Master of Business Administration Degree with a concentration in finance by the University of Florida. From 1984 to January, 1990 I was employed by the Florida Department of Business Regulation as a financial analyst.

I began my employment with the Florida Public Service Commission in February of 1990, and have held various positions in the Bureau of Electric Regulation since that time. My primary job responsibilities are in the areas of electric utility cost of service and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss alternative regulatory treatments for Tampa Electric Company's (TECO) recent wholesale sales to the Florida Municipal Power Agency (FMPA) and the City of Lakeland (Lakeland), and to discuss TECO's proposed treatment of these transactions.

Q. Could you briefly describe the wholesale sale to Lakeland?

A. The sale to Lakeland began on October 19, 1996, and ends September 30, 2006. The sale is a firm 10 MW sale under Long-Term Service Schedule D, and is made from TECO's system generating resources. The sale has priority equal to that of TECO's firm native load. There is also provision for an additional 10 MW with a priority subordinate to TECO's native load and existing wholesale commitments.

Q. Could you briefly describe the wholesale sale to the FMPA?

A. The sale to the FMPA began on December 16, 1996, and ends March 15, 2001. This sale is a firm Schedule D sale of capacity and energy from TECO's Big Bend Units 2 and 3, and Gannon Units 5 and 6. The FMPA is entitled to this capacity any time these units are able to supply it. For the initial year of the agreement, the sale is for 35 MW of capacity, and increases annually over the term of the contract to a level of 150 MW by the end. The contract also makes provision for the supply of supplemental capacity at the same reliability as the base capacity, once it is scheduled.

Q. Has TECO made similar sales in the past?

A. Yes. TECO has made long-term firm Schedule D sales to various entities from its Big Bend Generating Station.

Q. How were these sales treated in TECO's last rate case in Docket No. 920324-EI?

A. The sales were separated from the retail jurisdiction and placed in the wholesale jurisdiction. The separation allocated the generation and transmission rate base and non-fuel expenses (i.e. Operations and

Maintenance (O&M), depreciation, taxes, etc.) between the retail and wholesale jurisdictions, based primarily on each jurisdiction's contribution to the 12 monthly system peak demands. The variable O&M generation expenses were allocated on an energy, or per kilowatt hour, basis. Retail rates were then set based on the rate base and expenses allocated to the retail side, while on the wholesale side TECO's revenues and the resulting return were dictated by the agreements they negotiated with the separated wholesale customers, subject to the FERC's approval. Revenues from separated sales (with the exception of fuel revenues, which are addressed in the Fuel and Purchased Power Cost Recovery (Fuel) Clause), are retained by the stockholders.

Q. How are the fuel revenues from separated sales treated for regulatory purposes?

A. The fuel revenues are credited to the retail Fuel Clause to reduce the total system fuel costs paid for by the retail ratepayers. The Commission recently addressed the treatment of fuel revenues for wholesale sales in Docket 970001-ET, Order No. PSC-97-0262-FOF-EI, dated March 11, 1997. The Commission established a policy for new separated sales which requires that the fuel revenues returned to the ratepayers be equal to the system average fuel cost, regardless of how the fuel was priced pursuant to the wholesale contract, unless the utility could demonstrate net benefits to the ratepayers from the sale.

Q. How did TECO propose to treat the Long-term Firm Schedule D transactions in the rate case in Docket 920324-EI?

A. TECO proposed that the sales be included in the retail jurisdiction.

When wholesale sales are retained in the retail jurisdiction, the retail ratepayers support through their rates the entire cost of the plant and expenses associated with the sales.

In addition, TECO proposed that 60% of the non-fuel revenues from the Big Bend Schedule D and other interchange sales be retained below the line by TECO's stockholders, and that the remaining 40% be returned to the ratepayers through the Fuel Clause.

Q. Did the Commission approve this treatment?

A. No. The Commission rejected TECO's proposed sharing of non-fuel revenues in Order Nos. PSC-93-0166-FOF-EI and PSC-93-0664-FOF-EI. The Long-term Firm Schedule D sales were separated, and their costs and revenues were placed in the wholesale jurisdiction.

For those interchange sales which were retained in the retail jurisdiction (with the exception of broker sales), the Commission ordered TECO to credit all of the non-fuel revenues back to the ratepayers through the adjustment clauses: the O&M revenues through the fuel adjustment clause, and the capacity revenues through the capacity cost recovery clause.

Q. Does TECO's proposed retail jurisdictional treatment of the FMPA and Lakeland sales comport with existing Commission policy for these types of sales?

A. Absent a demonstration that TECO's ratepayers benefit from the proposed treatment, it does not. TECO's proposal would retain the sales in the retail jurisdiction, which does not appear to establish a fair balance between ratepayers and stockholders. The FMPA and Lakeland sales do not

differ substantially from those firm Schedule D sales which are currently separated into the wholesale jurisdiction. They are all firm, long-term (i.e. longer than one year) sales that require TECO to commit capacity from either specified units or system generating resources. The capacity thus committed is no longer available for use by the retail ratepayers. Further, since the revenues derived from the sales are less than the embedded average cost of the sales, inclusion of these sales in the retail jurisdiction allows TECO to subsidize its wholesale sales at the expense of the captive retail ratepayers.

Based upon Commission policy established in TECO's last rate case, any new long-term firm sales should be separated into the wholesale jurisdiction based upon average embedded costs. In addition, pursuant to the Commission's recent Order No. PSC-97-0262-FOF-EI in Docket 970001-EI, the retail ratepayers should be credited with no less than an amount equal to the system average fuel revenues from these sales, regardless of the actual fuel revenues received. Any exceptions to these policies should be addressed on a case-by-case basis, where it can be demonstrated that an alternative treatment is in the best interests of the ratepayers.

Q. Has TECO demonstrated that their proposed treatment of the FMPA and Lakeland sales is in the best interest of the ratepayers?

A. TECO has sought to include the FMPA and Lakeland sales within the retail jurisdiction because they believe that they can no longer compete in the wholesale market by pricing sales based upon their average embedded cost. With the addition of the Polk IGCC unit (which has resulted in a 58 percent increase in TECO's total net generation plant in service between

[illegible] and 1998) future wholesale sales based on TECO's system average cost appear to be particularly threatened. TECO believes that requiring separation under these circumstances creates a strong disincentive to make such sales, since the stockholders are required to absorb the entire shortfall between average embedded costs and the revenues from the sales.

TECO reasons that as long as the revenues from wholesale sales are greater than the incremental cost of producing the energy sold, the ratepayers are better off. TECO has filed a cost-effectiveness analysis of the FMPA and Lakeland sales which purports to show that the sales will produce net benefits to the ratepayers. However, this analysis is based on projected incremental costs and revenues associated with the FMPA and Lakeland sales and there is no assurance that they will continue to be cost-effective throughout the terms of the contracts. I have further concerns regarding TECO's estimate of the possible impact of these sales upon TECO's generation expansion plan. Because of the need of further discovery to determine the reasonableness of TECO's incremental cost-benefit analysis, I cannot make a determination as to whether the sales provide net benefits to TECO's retail ratepayers.

Q. Do you believe TECO's proposed stockholder sharing of the revenues from these sales is appropriate?

A. Absolutely not. While it may be appropriate to remove the disincentive caused by requiring TECO to separate the sales, it is entirely inappropriate to provide any further incentive to make these sales.

Based on TECO's testimony, their proposed treatment of the revenues

for the FMPA sale result in the stockholders retaining $11.2 million, or about 82% of the total $13.7 million in NPV non-fuel revenues that are projected to be received over the life of the contract.

If the sales remain in the retail jurisdiction, the retail ratepayers are fully supporting the costs associated with these sales through their rates. As a consequence, they should receive the full benefit of all the revenues which result from them. All energy charge revenues, including fuel, should be credited to the ratepayers through the Fuel Clause. The capacity charge revenues should be credited through the Capacity Cost Recovery Clause.

It is incumbent upon a prudent utility to attempt to maximize wholesale revenues from temporary surplus capacity for the benefit of the retail ratepayers who are responsible for the costs of supporting that capacity. Pursuant to the "regulatory compact", TECO has been granted the exclusive right to serve the retail customers in its service territory, and the opportunity to earn a fair return on the investment required to serve those customers. In return, they must provide reliable service to all customers who request it at the lowest possible cost. TECO should not require additional incentive to fulfill this obligation to lower costs to its retail ratepayers by engaging in cost effective wholesale transactions.

Q. Are there any existing incentives for TECO to engage in wholesale transactions of this type?

A. Yes. The sales will result in benefits to wholly owned subsidiaries of TECO's parent company, TECO Energy, Inc. These affiliates provide coal and waterborne coal transportation to TECO. Increases in energy sales by

TECO will result in increased revenues to these affiliates.

Q. Do you believe it is appropriate for TECO to retain for its stockholders all of the revenues attributable to transmission services?

A. No. Pursuant to Federal Energy Regulatory Commission (FERC) orders 888 and 889, utilities are now required for wholesale sales to charge themselves for the use of their transmission systems just as they do any other user. Accordingly, a portion of the revenues from the FMPA and Lakeland sales must be identified as relating to transmission. This requirement does not justify TECO's proposed treatment under which its stockholders would retain all of the transmission revenues. Although the wholesale market for generation is *now* becoming more competitive, wholesale transmission rates remain a regulated monopoly, subject to the jurisdiction of the FERC. This would argue for the separation of all of these transmission related costs and revenues into the wholesale jurisdiction.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for a rate increase by Tampa Electric Company.) DOCKET NO. 920324-EI
) ORDER NO. PSC-93-0165-FOF-EI
) ISSUED: 02/02/93

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
BETTY EASLEY
LUIS J. LAUREDO

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on September 30, 1992, in Tallahassee, Florida; on October 7, 1992 in Tampa, Florida; and October 12 through 19, 1992 in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

LEE L. WILLIS, Esquire, JAMES D. BEASLEY, Esquire, and KENNETH R. HART, Esquire, Ausley, McMullen, McGehee, Carothers and Proctor, 227 South Calhoun Street, Post Office Box 391, Tallahassee, Florida 32302.
On behalf of Tampa Electric Company.

JOHN ROGER HOWE, Esquire, Deputy Public Counsel, and H. Floyd Mann II, Esquire, Associate Public Counsel, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400.
On behalf of the Citizens of the State of Florida.

JOHN W. McWHIRTER, JR., Esquire and LEWIS J. CONWELL, Esquire, McWhirter, Grandoff and Reeves, 201 East Kennedy Boulevard, Suite 800, Post Office Box 3350, Tampa, Florida 33601-3350; and VICKI GORDON KAUFMAN, Esquire and JOSEPH A. McGLOTHLIN, Esquire, McWhirter, Grandoff and Reeves, 315 South Calhoun Street, Suite 716, Tallahassee, Florida 32301.
On behalf of Florida Industrial Power Users Group.

DEBRA SWIM, Esquire and ROSS BURNAMAN, Esquire, 1115 North Gadsden Street, Tallahassee, Florida 32303-6237; and TERRY BLACK, Esquire, Pace University Energy Project, Center for Environmental Legal Studies, 78 North Broadway, White Plains, New York 10603.
On behalf of Legal Environmental Assistance Foundation/John Ryan.

DOCUMENT NUMBER-DATE
01243 FEB-2 93
FPSC-RECORDS/REPORTING

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PAMELA K. AKIN, City Attorney and TYRON BROWN, Esquire, 315 East Kennedy Boulevard, 5th Floor, City Hall, Tampa Florida 33602.
On behalf of City of Tampa.

LT. COL. BRUCE J. BARNARD, and CAPT. TERRIE M. GENT, AFLSA/ULT, 139 Barnes Drive, Tyndall AFB, FL 32403-5319.
On behalf of the Department of Air Force.

PATRICK K. WIGGINS, Esquire, Wiggins and Villacorta, P.A., 501 East Tennessee Street, Tallahassee, Florida 32302
On behalf of District School Board of Pasco County, Florida.

ROBERT V. ELIAS, Esquire, DONNA L. CANZANO, Esquire, MICHAEL A. PALECKI, Esquire, and M. ROBERT CHRIST, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0863
On behalf of the Commission Staff.

PRENTICE P. PRUITT, Esquire, Florida Public Service Commission, 101 E. Gaines Street, Tallahassee, Florida 32399-0862
On behalf of the Commissioners.

ORDER GRANTING CERTAIN INCREASES

CASE BACKGROUND

On May 22, 1992, Tampa Electric Company (TECO or Tampa Electric or the company or the utility) filed a Petition for an increase in its rates and charges and approval of a fair and reasonable rate of return. The petition seeks a permanent increase in TECO's rates and charges pursuant to Section 366.06, Florida Statutes. The petition cites the costs associated with building and maintaining an adequate and reliable production, transmission and distribution system; the cost of serving over 106,000 new customers expected to take service by 1993 as compared to 1984 (the test year in the company's last rate proceeding); and the effects of a 41% expected increase in inflation from the end of 1984 through 1993 as factors creating the need for higher rates.

d) TECO will include in its tariff a provision indicating that the company normally will replace burned out street lights within three working days of notification by the customer.

The appropriate level of the Emergency Relay Power Service Charge is set out for the applicable rate schedules in MFR Schedule E-16c.

The CIAC shall be equal to the cost of additional facilities required to provide emergency relay power service.

The amount of CIAC a customer is required to contribute to purchase a Time-of-Day meter shall be equal to the difference in cost between a regular meter and a Time-of-Day meter.

IX. OTHER ISSUES

A. Settlement Charges By Utley-James Oakes

Concurrently with the Staff financial audit, an engineering audit of expenses associated with Big Bend 4 (BB4) was also conducted (Exh. 85). Audit Disclosure No.4 of the Staff Audit Report (Exh. 83) stated that due to resequencing of work, design interferences, and schedule accelerations, Utley-James/Oakes billed TECO for additional charges for an amount in excess of the $850,000 that through negotiations TECO agreed to pay to Utley-James/Oakes. The audit opinion stated that the charges did not represent normal costs of installation but were the result of poor performance by various vendors and TECO, and that as a result these charges should have been expensed rather than capitalized.

The construction of BB4 was very complex, and the record indicates that there were numerous delays encountered during the construction of this facility but it is not possible to determine that any adjustment is warranted. In addition, there is no explanation to support any adjustment amount, other than the fact that the $850,000 is what TECO settled for. The company stated in its response in Issue 9, that certain changes were outside its direct control and that the plant was constructed on budget and was placed in Rate Base on time. To assess TECO's judgment at this point in time would be inappropriate. The original claim against TECO amounted to $1,500,000; through negotiations this amount was reduced to little more than half of the original figure. By negotiating this settlement, TECO demonstrated that it attempted to hold the ultimate construction costs of this plant to a minimum and was not simply planning to ultimately pass through all costs of BB4

to the ratepayers without a review. Therefore, we find that these settlement charges in the amount of $850,000 by Utley-James/Oakes on contract BB4-04 were appropriate and should remain part of the capitalized costs of BB4.

B. Capacity Associated With Purchase And Sharing Of Hardee Power Station

The Commission granted a determination of need for the 295 MW Hardee Power Station capacity to Seminole Electric Cooperative (SEC). TECO Power Services (TPS) responded to the SEC Request for Proposal (RFP) for backup power to back up Seminole's existing coal fired units. The Commission bifurcated Docket No. 880309, the need determination docket, and made two findings. First, in Order No. 20930 the Commission found that SEC had established a need for 450 MW of capacity in 1993, and second, in Order No. 22335 the Commission found that the TPS proposal satisfied SEC's need in the most cost-effective manner to SEC and provides adequate electricity at a reasonable cost.

Tampa Electric's participation in the sharing of the Hardee capacity with Seminole Electric results in the deferral of 225 MW of combustion turbine capacity in the Tampa Electric Company's twenty year plan. (TR 255) Seminole will use the Hardee unit to meet its need for backup power during the spring and fall maintenance outages of its existing units, while Tampa Electric's new capacity needs are in the winter and summer months. (TR 255) Tampa Electric will pay TPS an amount equal to 40% of the Hardee capacity and energy charges, with Seminole responsible for the remaining 60% of capacity and energy charges. (TR 529)

The Commission based the need finding on the economics inherent in the wholesale contracts between TPS, SEC and Tampa Electric. (Order No. 22335) In Phase I (1993-2003) TPS will construct 295 MW of combined cycle capacity and TECO will sell 145 MW of Big Bend 4 capacity to SEC, and in Phase II (2003-2013) TPS will replace the BB-4 capacity by constructing a 70 MW heat recovery unit and one 75 MW CT at the Polk/Hardee site for sale to SEC. (TR 254) The combination of the sale of existing BB-4 capacity and constructing new TPS capacity was preferred to the option of SEC constructing two 220 MW combined cycle units in 1993. The TPS proposal resulted in projected present worth of revenue requirements savings to SEC of approximately $57 million (1987 dollars) and projected present worth revenue requirement savings of $90 million (1989 dollars) to Tampa Electric based on the deferral of 225 MW of previously planned CT capacity on Tampa Electric's system. (Order No. 22335)

The Commission also recognized the sharing of 295 MW of Hardee Power Station capacity between Tampa Electric and SEC as purchased power in Tampa Electric's determination of need proceedings for the Polk County IGCC unit. (Order No. PSC-92-0002-FOF-EI) Accordingly, we find that Tampa Electric demonstrated that capacity associated with the Hardee Power Station is needed for its retail ratepayers in 1993 and 1994.

C. Capacity Costs Associated With The Purchase Of Power From The Hardee Power Station

TECO has requested that the capacity costs associated with the purchase of power from the Hardee Power Station flow through the new Capacity Cost Recovery Factor. We find that the annual Hardee Power capacity costs shall be recovered through the Capacity Cost Recovery Clause.

The three parties to the Hardee Power Station, Tampa Electric, TECO Power Services (TPS) and Seminole Electric Cooperative, have negotiated wholesale contracts for the purchase and sale of the 295 MW of combined cycle capacity. Tampa Electric proposed to collect the capacity charges associated with the Hardee Power Station through the Capacity Cost Recovery Clause. (TR 256) The company's contractually agreed upon monthly capacity charge paid to its affiliate TPS pursuant to the wholesale contract is $1,095,932. This number does not vary and could be allocated among rate classes and recovered through base rates. We shall permit cost recovery through the Capacity Cost Recovery Clause solely to keep components of the Hardee costs together. Because of the straightforwardness of the amount, we are actually indifferent to whether recovery is through base rates or the capacity cost recovery clause. Although arrangements such as the Hardee Power station may be more complicated than what was envisioned by the decision to recovery purchased power capacity costs through the Capacity Cost Recovery Clause, we believe the contract to be monitorable for cost recovery clause purposes.

The company's witness, Mr. Ramil, testified that Tampa Electric could have built the Hardee Plant instead of TPS. (TR 536-37) If this plant were constructed and owned by Tampa Electric, it would come under traditional cost of service regulation subject to the Commission's authorized return on equity. Because the plant is an Affiliated Power Production facility, it is entirely possible that these earnings could exceed the level approved by this Commission for rate base generating plant.

In traditional regulation, the capital cost recovery of a fixed asset such as a generating plant is included in rate base with the expense reflected in base rate charges recovered on a per kilowatt hour basis. Pursuant to the traditional treatment, the earnings of the company's stockholders vary due to the seasonality and variability of sales. This results in a certain level of risk associated with capital cost recovery which is borne by the stockholder for which they are compensated through the authorized return on equity. However, in the TPS Hardee purchase power contract, stockholder earnings are guaranteed pursuant to the proposed Purchased Power cost recovery of the Hardee Power capacity. Tampa Electric proposed to recover these capacity costs on a fixed levelized basis independent of sales levels. In other words, through the proposed recovery treatment, the parent company has decoupled the cost associated with the Hardee Station from sales.

D. Capacity Charges Through Hardee Power Station

TECO proposed $13,151,184 in annual capacity charges for the Hardee Power Capacity. (Exhibit 37) In Order No. 22335 issued December 22, 1989, the Commission approved the petition of Seminole Electric, TECO Power Services (TPS) and Tampa Electric for a Determination of Need for the Hardee Power Project as well as the wholesale power sales contract between TECO, TPS and Seminole. Annual capacity charges in the amount of $13,151,184 are in accordance with the power sales contract. Tampa Electric's off-system sales revenues from the Hardee Power Station for all interchange sales shall flow through the Capacity Cost Recovery Clause.

E. O&M Costs Associated With Purchase Of Power From Hardee Power Station

TECO has requested that the fuel and O&M costs associated with the purchase of power from the Hardee Power Station flow through the Fuel Adjustment Clause. We shall allow recovery of actual Hardee Power fuel costs through the fuel cost recovery clause because these costs will vary with the amount of energy produced and the market price of fuel. If actual O&M expenses exceed projected amounts shown in Exhibit 37, Tampa Electric shall notify the Commission prior to the hearing and justify any O&M expenditures which exceed the projected amounts during the period 1993-1997. Prior to 1997, the company shall provide Staff with projected O&M costs for the remainder of Phase I through 2003. This treatment will provide the company with the opportunity to

recover O&M expenditures exceeding the projected levels after providing justification for these expenditures as well as to provide the Commission with additional cost information relating to the total cost of Hardee Power Project.

Tampa Electric projects annual fixed and variable O&M costs ranging from approximately 1.45 million to 3.0 million for the period 1993-1997. (Exhibit 37) These cost vary from period to period depending on the planned outage and maintenance schedules for the Hardee Power Plant. The Commission contemplated Purchased Power Capacity clause recovery of related O&M costs in the generic investigation, Docket No. 910794-EQ. However, the Commission made no finding in the proceeding and stated that "While there may be merit in these suggestions, we do not have sufficient information at this point to determine definitively what additional items may be appropriate." The Commission indicated that inclusion of O&M expenditures would require consideration in a rate case or other generic proceeding to determine the exact nature and magnitude of such charges. (Order No. 25773)

Because the O&M benchmark is based on projections and because of the requirement for specific justifications to recover O&M costs if exceeded, we find that actual fuel and O&M costs shall be recovered through the Fuel Adjustment Clause. Tampa Electric shall be required to justify annual O&M costs exceeding those amounts projected by the Company in Exhibit No. 37 for the period 1993-1997 and provide updated projections for future periods.

F. Reward/Penalty For Corporate Performance

The issue of whether or not Tampa Electric should be given a reward or penalty for its corporate performance in the areas of residential rates, customer service, and energy efficiency programs was raised by the Commission staff. We believe that staff has an obligation to look into these matters and bring them to our attention when appropriate. However, we are reluctant, unless the conditions seem to be fairly extreme one way or the other, to grant a reward or impose a penalty.

TECO has the highest rates on a per 1000 kwh basis of the Peninsular IOU's, but its average residential revenue divided by residential sales yields a rate that is between the other two IOU's. With regard to customer complaints, Ms. Pruitt (staff's witness) testified that justified complaints per 1000 customers has been higher for TECO than the industry as a whole for three of the past five years, but TECO's individual complaints have decreased every year, but one, since 1987. (TR 1483-1484) TECO's

conservation efforts have been comparable with other IOU's in that more emphasis is placed on demand reducing programs than energy reducing programs. TECO's conservation programs have been approved by the Commission and are consistent with the statutory requirement that conservation programs be cost-effective.

Therefore, we find that TECO shall not be rewarded or penalized in this rate case since it appears that TECO's management has neither excelled nor failed in its corporate performance in the areas of residential rates, customer service, and energy efficiency programs.

G. Broker Sales

We believe that Tampa Electric Company has acted appropriately in making off-system sales of excess capacity rather than as-available one hour sales transactions through the Florida Energy Broker System.

The Commission's treatment of surplus Big Bend capacity in TECO's last rate case (Docket No. 850050-EI) encouraged what we believe are appropriate actions to maximize off-system sales. In TECO's last rate case, the Commission established an off-system sales target for surplus Big Bend capacity by imputing $37.1 million in revenues for off-system sales. This gave TECO an incentive to make as many non-Broker sales as possible since 100% of non-Broker sales revenues offsets the sales revenue imputation made by the Commission in the last rate case.

TECO has not, since the last rate case, achieved $37.1 million dollars in annual off-system sales revenue. Thus, in some respects, the shareholders have been disadvantaged by the imputation of revenue.

Profits from as-available sales through the broker system are split with 80% enuring to the benefit of the ratepayers and 20% enuring to the benefit of the shareholders. It has been suggested that in making off-system sales, TECO has bypassed the Broker System so that more of the profits from these transactions would accrue to the shareholders. The testimony we heard does not support such a finding.

In its position, TECO states "If a utility can bring greater revenue to its system by selling power through another interchange agreement it should be encouraged to do so." We agree. By imputing $37.1 million in revenues for off-system sales we established an incentive for TECO to pursue off-system sales. The

greater weight of the evidence suggests that TECO acted appropriately in marketing its excess capacity.

H. Appropriate Treatment Of Revenues Associated With Off-System Sales, Incentives

Staff recommended that all capacity revenues from off-system sales should be credited to the Capacity Cost Recovery Clause and that all off-system O&M revenues credited to the Purchased Power and Fuel Cost Recovery Clause. Staff proposed this treatment because of the variability of off-system revenues, which depend on the needs of Tampa Electric's neighboring utilities, the prevailing market conditions, and competing fuel prices. Uncertainty in projecting off-system revenues presents a problem when determining base rates in a rate case.

If in future years, actual revenues are greater than the forecasted amount included in base rate determination, the ratepayers are penalized and the company retains the excess revenues for its stockholders. The opposite is true if actual revenues are less than the forecasted amount benefiting the ratepayers. Since forecasting the revenue impact of future off system sales revenues is difficult because of the numerous assumptions contained in the forecast which may or may not prove accurate over time, staff recommended crediting off-system capacity revenues to the Capacity Cost Recovery Clause, and removing the projected off-system O&M revenues of $2.75 million in 1993 and $3.88 million in 1994 from base rate revenues and crediting these amounts to the Fuel Cost Recovery Clause.

Forecasting levels of off-system sales is far from an exact process. In his testimony, Tampa Electric's witness, Mr. Ramil, projects $11.9 million of off-system transactions in 1993 not including the Sebring and TECO Power Services sales. This is roughly half of the 8 month actual/4 month forecast amount of $23 million of off-system sales revenues for the current year 1992. Tampa Electric will likely have the opportunity for additional off-system sales starting in 1993 when the Hardee Power Station capacity of 295 MW comes on-line.

The revenue effect of incorrectly forecasting off-system sales from year to year will be eliminated if the revenues are credited through the Capacity Cost Recovery and Fuel and Purchased Power Clauses. Our treatment eliminates the potential inaccuracy from forecasting the level of off-system sales to be included in the calculation of base rate revenues.

All revenues and expenses associated with the firm Schedule D sales for the cities of New Smyrna Beach, St. Cloud and Wauchula, the Reedy Creek Improvement District and the Florida Municipal Power Association have been removed from the retail jurisdiction in the stipulated jurisdictional separation study.

Accordingly, we find that all revenues from off-system sales not allocated to the wholesale jurisdictional shall be included as credits in the Capacity Cost Recovery and Fuel and Purchased Power Cost Recovery Clauses. The capacity revenues shall be credited to the Capacity Cost Recovery Clause with O&M revenues credited to the Fuel and Purchased Power Cost Recovery Clause. We remove projected O&M revenues from off-system sales of $2,750,000 jurisdictional in 1993 and $3,888,000 jurisdictional in 1994 from base rate revenues.

Tampa Electric has proposed a sharing of the benefits of certain off-system sales described in Mr. Ramil's testimony (modified in accordance with the revised jurisdictional separation), in order to preserve an incentive for engaging in off-system sales which was incorporated in Tampa Electric's last full rate proceeding in Docket No. 850050-EI. TECO claims that retention of this incentive will directly benefit Tampa Electric's retail Customers.

Tampa Electric proposes to retain 60 percent of the capacity revenues from off-system sales other than those in the wholesale jurisdiction for the benefit of their stockholders and flow the remaining 40 percent of these revenues through the Capacity Cost Recovery clause for the benefit of the ratepayers.

Staff recommended that the Commission reject Tampa Electric's proposed 60/40 stockholder/ratepayer sharing of off system sales capacity revenues as unnecessary. Staff suggested that a prudently managed utility would use its best efforts to market this capacity and energy irrespective of whether it receives an additional incentive for doing so.

If the Commission decides to explore incentives, staff recommended that this issue be investigated in a generic docket. At that time, the Commission can explore the issue of off-system sales incentives as well as penalties for low levels of off-system sales or continued high levels of surplus capacity. This proceeding would allow the Commission the opportunity to adopt a uniform approach for all companies if it determines that incentives and penalties are needed for levels of off-system sales of generating capacity.

We believe that a generic proceeding to consider this issue is appropriate. We direct staff to initiate a docket to investigate and consider stockholder incentives for off-system sales.

By our decision to credit the revenues associated with off-system sales through the Capacity Cost and Fuel and Purchased Power cost recovery clauses, we have not maintained the status quo for Tampa Electric Company. In addition to the imputation of 37.1 million dollars of revenue in the last rate case, in that case we established a sharing of the annual revenues in excess of that amount. The stockholders would have received 20% of the revenue above that level and the ratepayers 80%. Since the target level of off-system sales was never achieved, no sharing ever occurred.

We believe that incentives can be useful in maximizing the level of off-system sales. Maximizing off-system sales makes the best use of the available capacity and can help minimize rates. The time necessary to conduct and decide a generic proceeding to determine an appropriate, industry-wide policy is likely to yield an effective date of October, 1993 at the earliest. This means that there will be less incentive for TECO to pursue off-system capacity sales and the carrying cost of any unused capacity will be paid by the ratepayers.

As an interim method to maximize the potential off-system revenues between the effective date of this Order and the decision in the generic proceeding, we establish the following incentive for Tampa Electric Company: We establish an $18 million dollar 1993 annual revenue target for off-system sales of excess jurisdictional capacity. Below that level, all the revenues will be credited, as discussed, through the Capacity and Fuel and Purchased Power Cost Recovery Clauses. Above $18 million dollars; 80% of the revenues shall be credited through Capacity and Fuel and Purchased Power Cost Recovery Clauses and 20% of the revenues shall be retained by the shareholders. The $18 million dollar target shall exclude TECO's commitments to the Utilities Commission of the City of New Smyrna Beach, the Reedy Creek Improvement District, the City of Wauchula and the Florida Municipal Power Association (the previously identified Schedule D sales).

I. Justifying Decisions Not To Competitively Bid Contracts For Architect/Engineering Services For Power Plant Construction

This issue was developed as a result of Audit Disclosure No. 1 in the Staff Audit Report. All of TECO's generating plants that are in rate base have been designed and engineered by Stone and Webster Engineering Corporation (SWEC) under cost plus type

contracts without benefit of competitive bidding. The audit opinion section of Audit Disclosure No. 1 in the Staff Audit Report states

> The accepted industry-wide practice for selecting a contractor for needed services, is the bidding process where the owner requests proposals from qualified vendors/contractors, then makes an impartial evaluation of the bids and awards the contract to the lowest evaluated bidder. By consistently sole sourcing with the same A/E, it cannot be determined whether the company received the best value for their money and therefore provided the rate payer with the most economical rates possible.

The report recommended that TECO should reverse its practice of awarding A/E contracts to the same company, SWEC.

The Company in their response to the audit disclosure, and in Mr. Ramil's rebuttal testimony states that since 1981, the Company policy has been to competitively bid A/E services. TECO recognizes that there may be instances where sole sourcing may be prudent and would justify that approach when employed.

Accordingly we find that TECO shall be required to justify any instance when it does not competitively bid for Architect /Engineering services.

J. Implementation Of Revenue And Sales Decoupling; And Implementation Of Demand Side Management Incentives

All Parties taking positions on these issues (LEAF, FIPUG and TECO) entered in to a stipulation stating that Docket No. 920606-EG (the Conservation Goals Rule)is an appropriate docket for the Commission's consideration of decoupling, rate impact measure, and DSM incentives. We agree. Accordingly we approve the stipulation entered by the parties. We find that these issues are moot for the purposes of resolving the matters necessary to reach a decision on Tampa Electric Company's petition for a Rate Increase.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Testimony and Exhibits of Kent D. Taylor have been furnished by *hand delivery, or U.S. Mail this 18th day of October, 1999, to the following:

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Appendix I

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Education

A.A., Liberal Arts, Pensacola Junior College, 1985.
B.A., History, University of West Florida, 1987.
M.S., International Affairs, Florida State University, 1988.
M.S., Economics, Florida State University, 1992.
Ph.D. , Economics, Florida State University, 1995.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

Academic Appointments

Louisiana State University, Baton Rouge, Louisiana
Center for Energy Studies

1995- Assistant Professor

E.J. Ourso College of Business Administration
Department of Economics

1999- Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
Department of Economics

1995 Instructor

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DOCKET NO. 990001-EI EXHIBIT NO. 39
COMPANY/
WITNESS: Dismukes
DATE: 11-22-99

Professional Experience

Acadian Consulting Group, Baton Rouge, Louisiana

1995- Consulting Economist/Principal

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993 Planning & Research Economist
1992-1993 Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992 Research Associate
1989-1991 Senior Research Analyst
1988-1989 Research Analyst

Publications: Peer Reviewed Academic Journals

"The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

"A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal.* 63:1108-1112.

"Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

"Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

"Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics.* 21:153-166.

Publications: Peer Reviewed Proceedings

"Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996,* January.

"Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

"New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

"Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

Publications: Other Proceedings

"Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

"Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

"Modeling Electric Power Markets in a Restructured Environment" (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology's Critical Role in Energy and Environmental Markets*. October: 48-56.

"Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

Publications: Books

Power System Operations and Planning in a Competitive Market. (2000) With Fred I. Denny. New York: CRC Press. *(In Progress, Anticipated Completion December 2000)*

Publications: Book Chapters

"Electric Power Generation." (1999). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference. *(forthcoming)*

Publications: Book Reviews

Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

Publications: Trade and Professional Journals

"Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

"Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly.* February 1: 30-33.

"Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

"Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With Skip Hughes. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

"Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With Skip Hughes. *Oil, Gas, and Energy Quarterly. (forthcoming, December).*

Publications: Reports, Monographs, and Other Publications

Restructuring the Electric Utility Industry: Implications for Louisiana. (1996). With Allan Pulsipher and Kimberly H. Dismukes. Louisiana State University: Center for Energy Studies.

Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS. (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Louisiana State University: Center for Energy Studies.

Publications: Internet Publications/Homepages

Electric Restructuring In Louisiana. Louisiana State University, Center for Energy Studies.
HTTP://WWW.ENRG.LSU.EDU

Grant Research

Co-Principal Investigator. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

Principal Investigator. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring" (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

Principal Investigator. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources. Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Awarded, In Progress.

Principal Investigator. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Awarded, In Progress.

Principal Investigator. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Awarded, In Progress.

Co-Principal Investigator. "Deepwater OCS-Related Infrastructure in the Gulf of Mexico." (1999). With Allan G. Pulsipher, Omowumi Iledare, and Dmitry Mesyanzhinov. U.S. Department of Interior, Minerals Management Service. Total Proposed Project Funding: $174,582. Status: Awarded, In Progress.

Principal Investigator. "Operational Support for Creation of a Gulf Coast Regional Distributed Energy Resource Center." (1999). With Ritchie Priddy. Variable Funding Sources and Amounts. Status: Ongoing, Currently Under Review by Institute of Gas Technology, Chicago, Illinois.

Academic Conference Presentations

"A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

"Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

"Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

"Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

"Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

"Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

"Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

"Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

"The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

"Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

"New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

"A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

"Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

"Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

"Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

"Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

"Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

"Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

"Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

"Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

"Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

"Potential Generation Efficiency Gains from Electric Power Industry Competition." (1999). With Williams O. Olatubi. Southern Economic Association Annual Conference. New Orleans, November. *(forthcoming)*

Academic Seminars and Presentations

"The Empirical Determinants of Cogenerated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

"Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

"Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

Professional and Civic Presentations

Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

"Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

"Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

"Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

"Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

"Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

"Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

"Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

"Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

"The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

"Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

"Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

"Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

"Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

"How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

"The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

"A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

"What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

"The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

"The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

"The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

Expert Witness and Legislative Testimony

Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

Docket 940448-EG -- 940551-EG, (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power

Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

Docket 950495-WS, (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

Editorial Appointments

Referee, *Energy Journal*
Contributing Editor, *Oil, Gas and Energy Quarterly*

Professional Associations

American Economic Association, American Statistical Association, Econometric Society, Omicron Delta Epsilon, Southern Economic Association, Western Economic Association, and the International Association of Energy Economists.

University Service and Activities

Louisiana State University Graduate Faculty, Associate Member. Term: 1999-2005.

Louisiana State University Faculty Senate, Student Recruiting and Retention Committee. Term: 1999-2002.

Louisiana State University Faculty Senate, Public Relations Committee. Term: 1996-1999

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. 1997.

Advisor on Electric Utility Restructuring Issues. Louisiana Public Service Commission Staff. (1996-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring. 1996-Current. Organized seminars include:

> "Efficiency and Environmental Implications of Electric Restructuring." Louisiana State University, LSU Faculty Club. April 29, 1996
>
> "Stranded Costs and Electric Restructuring." Louisiana State University, Lod Cook Alumni Center. May 29, 1996
>
> "Electric Restructuring: Costs and Benefits." Louisiana State University. Lod Cook Alumni Center. September 30, 1996.
>
> "Electric Restructuring Experiments and Proposals." Louisiana State University. Lod Cook Alumni Center. October 31, 1996.

"Federal and State Electric Restructuring Legislation." Louisiana Public Service Commission Hearing Room. March 18, 1997.

"Independent System Operators." Louisiana State University. Lod Cook Alumni Center. September 22, 1997.

Center for Energy Studies, Energy Information Center/CCEER Building Committee. 1999-Current.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 990001-EI EXHIBIT NO. 40
COMPANY/ WITNESS: Harlow
DATE: 11-22-99

Q (By Mr. Keating) I'm hoping you can answer this question for me. At Mr. Slusser's deposition, at which I think you were present at --

A Yes.

Q -- he discussed the actions by Florida Power Corporation and other utilities to make economy sales outside the Energy Broker Network.

Could you briefly describe how these nonbroker sales are arranged between utilities?

A Well, we have a fairly active power marketing department that really is in charge of doing that, and essentially they work much like any other broker operation.

They have computers. They have -- you know, they're constantly in touch. They look at -- you know, they're both in verbal and by computer communication with other companies, not only here in Florida, but outside of Florida, and are constantly buying and selling energy that, you know, falls into that economy transaction.

So, you know, in some instances companies will just call and ask us if they have anything -- if we have anything to sell. In some cases they're -- I don't think I'd call them RFP's, but they're basically, you know, posting prices that people are willing to sell for.

So it's a -- you know, it's a fairly -- it's a very open market where a lot of communication takes place between all the parties, and the arrangements are just made basically over the phone between brokers. And we do both our buying and selling that way.

Q Do you expect that these types of off-broker economy sales will start to edge out or reduce the sales that are made by Florida Power Corporation on the Broker Network?

A Well, I think they already have. I mean, if you compare -- and, in fact, I've done that out of curiosity -- if you go back a couple years and just look at our A schedules that we filed and, you know, look at broker versus nonbroker sales, it used to be -- even four years ago it used to be 90% broker and maybe a little piddling of other things; and now it's basically the other way around.

Q Do you expect that trend to continue?

A Yes, although it's -- I mean, I -- you can't really go much beyond 90% without wiping out broker sales altogether; and I don't think they're going to go away. So we may already have reached a -- you know, sort of a level, a new level.

Staff's First Set of Interrogatories
Docket No. 990001-EI
GULF POWER COMPANY
May 26, 1999
Item No. 1
Page 1 of 3

1. Please indicate whether Gulf calculates the 80%/20% incentive mechanism, as set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, on non-separated wholesale energy sales other than economy energy sales made through Energy Broker Network (formerly known as the Florida Energy Broker System). If so, please respond to the following:

   a. Please identify all other types of non-separated wholesale energy sales on which Gulf calculates the 80%/20% incentive mechanism.

   b. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a, above, please indicate the authority which requires or permits Gulf to calculate the 80%/20% incentive mechanism on such sales.

   c. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a. above, please indicate on an annual basis from 1990 to 1998 the amount of and total revenues from energy sold by Gulf.

   d. For each type of non-separated wholesale energy sale identified in Gulf's response to Interrogatory No. 1a above, please indicate on an annual basis from 1990 to 1998 the generation-related gain on such sales by Gulf. For purposes of responding to this interrogatory, the generation gain should be defined as total revenue received on a wholesale energy sale minus the sum of the following: incremental fuel costs, incremental O&M costs, and any transmission charge paid by the purchaser.

ANSWER:

Gulf Power Company calculates the 80%/20% incentive mechanism on non-separated wholesale economy energy sales not made through the Energy Broker Network. Gulf does not make economy energy sales through the Energy Broker Network.

   a. Gulf calculates the 80%/20% incentive mechanism on all of its non-separated wholesale economy energy sales, none of which are made through the Energy Broker Network. These sales are categorized by Gulf Power as "economy" sales and "external" sales to differentiate the sales based on whether they are made to non-affiliated utilities that are directly interconnected to the Southern electric system ("economy") or to non-affiliated utilities and power marketers that are <u>not</u> directly interconnected to the Southern electric system ("external").

b. In Order No. 12663 issued November 11, 1983 in Docket No. 830012-EU (TECO's rate case) the Commission decided to review in the next fuel adjustment proceeding whether or not gains from economy sales should be removed from base rates and considered in the fuel clause. In the generic fuel docket, No. 830001-EU-B, the Commission concluded in Order No. 12923 issued January 25, 1985 that it was appropriate to remove the profits associated with economy energy sales from base rates for all of the investor owned electric utilities and to include 80% of such profits in the fuel clause beginning April 1, 1984. To facilitate the change from base rate recovery to fuel clause recovery, the Commission "directed the utilities to provide the dollar amount of economy sales profits included in base rates in their most recent rate case." Gulf Power complied with this directive in a letter to the FPSC dated February 3, 1984. The staff reviewed this information along with similar information supplied by the other affected utilities and compiled a composite spreadsheet for the utilities to review. The composite spreadsheet was sent to Gulf and the other affected utilities by letter from Staff Counsel M. Robert Christ dated February 10, 1984. In Order No. 13092 (issued March 16, 1984 in Docket No. 840001-EU), the Commission acknowledged that the utilities' filings for the fuel cost recovery period beginning April 1, 1984 included ". . . economy energy sales profits in their projections for the April – September 1984 period based on the 80%/20% split between the ratepayers and the shareholders. Because the economy energy sales profits are currently in base rates, it is also necessary to adjust the base rates to exclude these profits as of April 1, 1984." A review of Schedule C attached to that order shows the adjustment to base rates proposed by Gulf was agreed to by staff and the 80%/20% split between the ratepayers and the shareholders for Gulf's economy energy sales. At that time, all of Gulf's economy energy sales were Schedule C economy sales made pursuant to FERC regulated interchange agreements between the operating companies of the Southern Company ("the Southern electric system") and non-affiliated utilities directly interconnected with the Southern electric system. Public Counsel appealed the Commission's order regarding the treatment of profits made by utilities in economy energy sales. The Florida Supreme Court affirmed the Commission's order in this case on February 28, 1985. Gulf has continued to include 80% of the profit associated with Schedule C economy sales as a credit to ratepayers through the fuel clause.

Since 1995, in addition to Gulf's Schedule C economy sales, the Company has made economy sales to utilities that are not directly interconnected with the Southern electric system (external sales) that include a markup similar to Schedule C economy sales. Gulf has consistently applied the directive of Order No. 12923 regarding the 80%/20% split of gain on economy sales to all of its non-separated wholesale economy sales, both those made to directly interconnected utilities (internally classified as "economy") and those to utilities that are not directly interconnected (internally classified as "external").

Staff's First Set of Interrogatories
Docket No. 990001-EI
GULF POWER COMPANY
May 26, 1999
Item No. 1
Page 3 of 3

c. Total Revenues Associated with Gulf's Non-separated Wholesale Energy Sales:

	Economy Sales		External Sales	
	Kwh	$	Kwh	$
1990	162,650,533	4,533,012	0	0
1991	34,087,642	944,372	0	0
1992	16,088,539	463,988	0	0
1993	59,132,645	1,714,384	0	0
1994	101,899,768	3,166,783	0	0
1995	44,339,013	1,327,585	277,927	6,435
1996	32,849,547	969,109	11,298,332	281,274
1997	76,641,743	2,212,222	61,543,208	1,850,438
1998	52,436,553	1,590,115	27,376,440	1,282,630

d. Generation-related Gains on Gulf's Non-separated Wholesale Energy Sales:

	Economy Sales	External Sales
	$	$
1990	742,959	0
1991	110,737	0
1992	50,099	0
1993	188,615	0
1994	320,847	0
1995	157,890	0
1996	86,758	0
1997	370,782	369,979
1998	257,606	669,167

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 1st SET OF INTERROGATORIES
INTERROGATORY NO. 1
SPONSOR: ZWOLAK/BROWN
PAGE 1 of 4

1. Please indicate whether TECO calculates the 80%/20% incentive mechanism, as set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, on non-separated wholesale energy sales other than economy energy sales made through Energy Broker Network (formerly known as the Florida Energy Broker System). If so, please respond to the following:

   a. Please identify all other types of non-separated wholesale energy sales on which TECO calculates the 80%/20% incentive mechanism.

   b. For each type of non-separated wholesale energy sale identified in TECO's response to Interrogatory No. la, above, please indicate the authority which requires or permits TECO to calculate the 80%/20% incentive mechanism on such sales.

   c. For each type of non-separated wholesale energy sale identified in TECO's response to Interrogatory No. la, above, please indicate on an annual basis from 1990 to 1998 the amount of and total revenues from energy sold by TECO.

   d. For each type of non-separated wholesale energy sale identified in TECO's response to Interrogatory No. la, above, please indicate on an annual basis from 1990 to 1998 the generation-related gain on such sales by TECO. For purposes of responding to this interrogatory, the generation-related gain should be defined as total revenue received on a wholesale energy sale minus the sum of the following: incremental fuel costs, incremental O&M costs, and any transmission charge paid by the purchaser.

A. Yes.

   a. Tampa Electric Company (TEC) calculates the 80%/20% incentive mechanism on all off-broker economy energy sales made through the Energy Broker Network (EBN) and off the EBN. All of these sales are made in accordance with Service Schedule C (Economy Energy Interchange Service) and Service Schedule X (Extended Economy Interchange Service) under TEC's Interchange Contracts.

   b. As stated in the response to Interrogatory No. 1.a., above, TEC calculates the 80%/20% incentive only on sales made under the FERC-approved Service Schedule C (Economy Energy Interchange Service) and

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 1st SET OF INTERROGATORIES
INTERROGATORY NO. 1
SPONSOR: ZWOLAK/BROWN
PAGE 2 of 4

Service Schedule X (Extended Economy Interchange Service). Both of theses interchange service agreements are termed "economy sales." In the case of Service Schedule C sale, these can be made either through the broker or off-broker. Service Schedule X sales can only be made off-broker.

Order No. 12923 issued in Docket No. 830001-EU-B in which the authority to calculate an 80%/20% incentive was given, refers to these sales as "economy energy transactions." This order stated,

> Economy energy transactions represent the sale of energy between electric companies. Gains are realized by the selling company as a result of the split-the-savings methodology used to calculate the selling price of economy energy.

There are numerous other Commission orders that address economy sales and their treatment. It is evident, especially in the earlier orders, such as Order No. 7890 issued on July 6, 1977 in Docket No. 74680-CI that economy sales are sales that allow more economical use of generating units. This order defined economy energy as:

> ...energy purchased and substituted for energy that would have been generated by the buying utility's own generating units at a higher cost.

Also, in Docket No. 810001-EU, Order No. 9957, issued April 20, 1981, the order listed several interchange schedule types and brief definitions. It specifically cited Service Schedule C (Economy) as a "split the savings concept."

Later orders and dockets refer to economy and "split-the-savings" interchangeably, with no reference to broker transactions.

Based on a historical review of the Commission's orders, including the specific order in which the 80%/20% incentive was approved, it is evident that the "split-the-savings" transaction is the type of sale upon which the incentive should be calculated. There is no differentiation within these dockets regarding the means utilized to enter into these transactions, however, the EBN was the automated tool established to facilitate economy energy transactions.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
STAFF'S 1st SET OF INTERROGATORIES
INTERROGATORY NO. 1
SPONSOR: ZWOLAK/BROWN
PAGE 3 of 4

Additionally, when reviewing historical practices, Service Schedule X sales (which are multi-hour, cost based economy transactions) have received similar treatment.

Economy transactions, both broker and non-broker, are cost-based, "split-the-savings" type transactions, approved by the FERC. The Commission approved an incentive mechanism in which gains on these transactions are split on an 80%/20% basis between the customers and the company, respectively.

c. TEC does not differentiate between economy transactions made on or off the broker. All of the energy broker sales data included in the attached table for 1990 through 1994 and the year 1998 was obtained from the EBN itself. The EBN also provided revenue data for the years 1990, 1991, 1993, 1994 and 1998. Neither energy data nor revenue data was available from the EBN for 1995 through 1997. Only energy data was available in 1992 and 1998.

d. The generation-related gain for all Service Schedule C and Service Schedule X sales is provided in the right hand column of the table referenced in the response to Interrogatory No. 1.c. As stated in that response, TEC does not differentiate between economy transactions as to whether or not they were made on or off the broker.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Fuel and purchased power cost recovery clause and generating performance incentive	DOCKET NO. 990001-EI DATE: JUNE 11, 1999

FLORIDA POWER & LIGHT COMPANY'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 14-43)

Florida Power & Light Company ("FPL") hereby provides this its Response to Staff's Second Set of Interrogatories (Nos. 14-43).

14. **Q. Please indicate whether FPL calculates the 80%/20% incentive mechanism, as set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, on non-separated wholesale energy sales other than economy energy sales made through Energy Broker Network (formerly known as the Florida Energy Broker System). If so please respond to the following:**

a) **Please identify all other types of non-separated wholesale energy sales on which FPL calculates the 80%/20% incentive mechanism.**

b) **For each type of non-separated wholesale energy sale identified in FPL's response to Interrogatory 14a, above, please indicate the authority which requires or permits FPL to calculate the 80%/20% incentive mechanism in such sales.**

c) **For each type of non-separated wholesale energy sale identified in FPL's response to Interrogatory 14a, above, please indicate on an annual basis from 1990 to 1998 the amount of and total revenues from energy sold by FPL.**

d) **For each type of non-separated wholesale energy sale identified in FPL's response to Interrogatory 14a, above, please indicate on an annual basis from 1990 to 1998 the generation-related gain on such sales by FPL. For purposes of responding to this interrogatory, the generation-related gain should be defined as the total revenue received on a wholesale energy sale minus the sum of the following: incremental fuel costs, incremental O&M costs, and any transmission charge paid by the purchaser.**

A. FPL only calculates the 80%/20% incentive mechanism on Schedule C economy sales through the Energy Broker Network. Accordingly, Order No. 12923 applies to economy sales, other non-separated sales are not affected by it. FPL returns 100% of any profit on other opportunity sales to our retail customers.

15. Q. **For regulatory purposes, please explain how FPL records transmission revenues derived from non-separated wholesale energy sales other than economy sales made through the Energy Broker Network (EBN).**

A. In response to this interrogatory, FPL has assumed that "non-separated wholesale energy sales other than economy sales made through the Energy Broker Network" are defined as non-EBN sales not reflected in the wholesale/retail separation used to set base rates, and at a minimum, the transaction includes a production and transmission component (e.g. Schedules A & B, and opportunity sales). For these sales, FPL credits (flows back) the transmission revenues to customers through the Capacity Clause.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor.

Docket No. 990001-EI

Submitted for filing: May 28, 1999

FLORIDA POWER CORPORATION'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER CORPORATION (NOS. 1-23)

Florida Power Corporation ("FPC") hereby responds to Staff's First Set of Interrogatories (Nos. 1-23), propounded April 26, 1999.

INTERROGATORIES

1. Please indicate whether Florida Power calculates the 80%/20% incentive mechanism, as set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, on non-separated wholesale energy sales other than economy energy sales made through Energy Broker Network (formerly known as the Florida Energy Broker System). If so please respond to the following:

a. Please identify all other types of non-separated wholesale energy sales on which Florida Power calculates the 80%/20% incentive mechanism.

b. For each type of non-separated wholesale energy sale identified in Florida Power's response to Interrogatory No. 1a, above, please indicate the

authority which requires or permits Florida Power to calculate the 80%/20% incentive mechanism on such sales.

c. For each type of non-separated wholesale energy sale identified in Florida Power's response to Interrogatory No. 1a, above, please indicate on an annual basis from 1990 to 1998 the amount of and total revenues from energy sold by Florida Power.

d. For each type of non-separated wholesale energy sale identified in Florida Power's response to Interrogatory No 1a, above, please indicate on an annual basis from 1990 to 1998 the generation-related gain on such sales by Florida Power. For purposes of responding to this interrogatory, the generation-related gain should be defined as total revenue received on a wholesale energy sale minus the sum of the following: incremental fuel costs, incremental O&M cost, and any transmission charge paid by the purchaser.

Response: Florida Power calculates the 80%/20% incentive only on sales made through the Energy Broker Network (EBN). 100% of the gain on all other sales are credited to customers.

Rebuttal Exhibit No. 41 (CRB-2), Document No. 1

Job Planning Procedure

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 99-0001-EI EXHIBIT NO. 41
COMPANY/
WITNESS: Black
DATE: 11-22-99

TECO
TAMPA ELECTRIC

Tampa Electric Company

SAFE WORK PRACTICES

SECTION 100
GENERAL

EXHIBIT NO. _____
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB – 2)
DOCUMENT NO. 1
FILED: 11/1/99
PAGE 1 OF 2

.03 Maintain adequate ventilation when work tasks such as cleaning, etc., may create potential airborne irritants.

.04 Maintain good housekeeping and minimize dusts and particulates. Avoid exposures through restricted uses of aerosols, solvents or other vapor producing products.

.05 Report unusual conditions or concerns to Building Services Dept. or your supervisor.

128 JOB PLANNING

.01 The employee in charge shall conduct a job briefing with the employees involved before they start each job. The briefing shall cover at least the following subjects: hazards associated with the job, work procedures involved, special precautions, energy source controls, and personal protective equipment requirements.

.02 The person in charge shall assemble the crew and explain the work to be done, outline the steps to be followed, personal protective equipment required, and point out the hazards of the job. The person in charge should ensure that each member of the crew understands the instructions.

.03 If the work or operations to be performed during the work day or shift are repetitive and similar, at least one job briefing shall be conducted before the start of the first job of each day or shift. Additional job briefings shall be held if significant changes, which

might affect the safety of the employees, occur during the course of the work.

.04 A brief discussion is satisfactory if the work involved is routine and if the employee, by virtue of training and experience, can reasonably be expected to recognize and avoid the hazards involved in the job. A more extensive discussion shall be conducted: if the work is complicated or particularly hazardous, or if the employee cannot be expected to recognize and avoid the hazards involved in the job.

.05 An employee working alone need not conduct a job briefing. However, the employee shall ensure that the tasks to be performed are planned as if a briefing were required.

.06 The person in charge is responsible for accounting for all employees upon the completion of each job.

129 LADDERS

.01 Only approved ladders shall be used in a safe manner. Manufacturers' weight limit shall not be exceeded.

.02 Ladders shall be visually inspected before they are used.

.03 Defective ladders shall be tagged and removed from service. If they are not repairable, they shall be destroyed.

EXHIBIT NO.
DOCKET NO. 990001-EI
TAMPA ELECTRIC COMPANY
(CRB – 2)
DOCUMENT NO. 1
FILED: 11/1/99
PAGE 2 OF 2