BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.	DOCKET NO. 060001-EI
PETITION TO RECOVER NATURAL GAS STORAGE PROJECT COSTS THROUGH THE FUEL COST RECOVERY CLAUSE, BY FLORIDA POWER & LIGHT COMPANY.	DOCKET NO. 060362-EI
PETITION FOR AUTHORITY TO RECOVER PRUDENTLY INCURRED STORM RESTORATION COSTS RELATED TO 2004 STORM SEASON THAT EXCEED STORM RESERVE BALANCE, BY FLORIDA POWER & LIGHT COMPANY.	DOCKET NO. 041291-EI

VOLUME 9

Pages 1126 through 1169

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER J. TERRY DEASON COMMISSIONER ISILIO ARRIAGA COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. TEW
DATE:	Friday, December 8, 2006

TIME: Commenced at 9:37 a.m.
Concluded at 10:56 a.m.

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

REPORTED BY: LINDA BOLES, CRR, RPR
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APPEARANCES:

LISA BENNETT, ESQUIRE; JOHN SLEMKEWICZ; BILL McNULTY; PETE LESTER and SID MATLOCK, appearing on behalf of the Commission Staff.

P R O C E E D I N G S

(Transcript continues in sequence from Volume 8.)

CHAIRMAN EDGAR: Good morning. I call this meeting to order, and I'd ask our staff counsel to read the notice.

MS. BENNETT: Pursuant to notice issued November 27th, 2006, this time and place has been set for a continuation of the November 6th and 8th hearing in Dockets Numbers 060001 and 060362. The purpose of the hearing is as set forth in that notice.

CHAIRMAN EDGAR: Thank you.

Commissioners, as I know you're aware, when we had the fuel docket hearing and vote, we had at least one and maybe more parties who requested the opportunity to file posthearing briefs on some issues, and our staff also asked for some additional time to review the testimony and accompanying information. And so we have continued that proceeding, which brings us here today on the remaining issues.

Ms. Bennett, how do you suggest we proceed?

MS. BENNETT: The notice set forth the MoBay docket, 362, first, so I would suggest that you start with that. It is your discretion as the Commission to hear each issue separately or staff could present them all together.

CHAIRMAN EDGAR: Okay. Thank you. Commissioners, if it works for you, I think what I'd like to do is take up the issues individually one by one. But before we ask our staff to give us a discussion or description of their recommendation on the first issue, are there any general comments or questions?

Commissioner Arriaga.

COMMISSIONER ARRIAGA: Madam Chairman, as you just stated, you prefer to go issue by issue. But to me they're so interrelated that if you allow me, I have a battery of questions here but they can be applied to all three issues. And then the answers to these questions will allow me to be able to vote individually.

CHAIRMAN EDGAR: That's fine.

COMMISSIONER ARRIAGA: So if all of you Commissioners are patient with me, I'm going to go ahead and make a set of questions. Is that okay?

CHAIRMAN EDGAR: I have all day.

(Laughter.)

COMMISSIONER ARRIAGA: I do until 5:00. I've got to catch a plane to the warmer weather, so.

Good morning, ladies and gentlemen from staff, or ladies and gentlemen. Let me start with a set of general questions first. Who is going to answer, please?

MR. SLEMKEWICZ: I will answer most of those questions on MoBay.

COMMISSIONER ARRIAGA: All right. Thank you.

Fuel inventory is typically in base rates filed in the company's MFRs. Did FPL file this project during the last rate case?

MR. SLEMKEWICZ: No, it did not.

COMMISSIONER ARRIAGA: Does a gas-fired plant require gas storage for its normal day-to-day operation or could the plant connect directly to the fuel supply?

MR. SLEMKEWICZ: It can connect directly to the fuel supply.

COMMISSIONER ARRIAGA: Can you please explain the difference between fuel inventory and gas storage, if any?

MR. SLEMKEWICZ: I don't see any difference between the two other than one is on-site and one is off-site. And it, and it's usually not practical -- you can do it, but it's not practical to store gas on-site because of, you know, geography and the terrain under the plant, you know. Whether -- you have to have some kind of, like a salt dome or something like that that can contain the gas.

COMMISSIONER ARRIAGA: So gas is usually stored outside?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER ARRIAGA: Can you define a physical hedge and how it is used?

MR. SLEMKEWICZ: A physical hedge is just, you know, buying a quantity of something in advance so that you have it on hand when you need it. I mean, that's a simple definition of, you know, what a physical hedge would be.

COMMISSIONER ARRIAGA: Do you think it is prudent practice to purchase high quality, high grade coal to use as a base coal?

MR. SLEMKEWICZ: Probably not, because that, it just forms the base and it gets crushed and it's really not usable. So you would want to get a lower grade of coal to form the base.

COMMISSIONER ARRIAGA: So it wouldn't be common practice to burn that base coal at the end of the life cycle of a plant and expect reasonably the same efficiency as a high quality coal.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER ARRIAGA: Let's go quickly to the issue of hedging. Does the hedging resolution allow IOUs to charge to the fuel cost recovery clause, and I quote, gains and losses associated with financial and/or physical hedging transactions for natural gas?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER ARRIAGA: I read in the record, specifically on Page 7 of Mr. Yupp's testimony from FPL, that there are several factors that can affect natural gas prices and availability during 2007, among others, growth of demand, availability of LNG and Canadian gas imports, capacity of existing pipeline systems. If a company becomes aware of these factors, is it not prudent to take precautionary measures such as physical hedging to try to minimize these adverse conditions?

MR. SLEMKEWICZ: That would be true.

COMMISSIONER ARRIAGA: Also in the same testimony it is stated by a publication by the Department of Energy that 47 of 54 members of the American Gas Association use gas storage as a primary hedging tool. In other words, this type of physical hedge is a nationwide common practice.

In addition, I am aware that electric companies not only have their own gas storages as their own physical hedges, but in order to protect themselves and the consumer from price volatility, they take positions or purchase other companies' physical hedges. Is that a fair assessment?

MR. SLEMKEWICZ: I really don't know the answer to that question. I don't know if Pete Lester or Bill McNulty might be aware of that.

COMMISSIONER ARRIAGA: Are you okay with the first part of the statement indicating that 47 of 54 members of AGA, as stated by the DOE, use gas storage as a primary hedging tool?

MR. McNULTY: I think we can agree with that. I don't think that that's really debatable. The thing about how you look at hedging sometimes is the purpose for which hedging is done. If I could characterize the hedging order, we got involved in a price hedging proposal and we adopted that price hedging proposal on the basis of reducing price volatility. And so we looked at, you know, the primary concern addressed as the volatility price. And -- but there are -- physical hedges do actually two things. Physical hedges can ensure both supply at the time that you need it as well as price. And I would just suggest to you that when we engaged in the hedging, the hedging order that's been discussed in this case, that our primary concern was price volatility rather than supply reliability. Physical hedge does both of those things.

COMMISSIONER ARRIAGA: And by reading the testimony, my understanding from different statements from the company is that what they intended was price volatility; I just stated, as I read from Mr. Yupp's testimony. But in any case, thank you so much.

Commissioners, when the Commission approved the hedging resolution, by doing so it intended, among other things, and I'm going to quote what it intended, to remove disincentives that might currently exist for IOUs to engage in hedging transactions. So when I -- this battery of questions and this resolution and staff recommendations pose a very big dilemma to me. And I'm going to say in colloquial terms, I can never, you know, overpass Commissioner Carter in his colloquialisms, but what I see in front of me is an animal that likes to walk on roofs, likes fish, expresses itself by saying "meow," and I don't know if I should call it a turkey or a cat dressed as a physical hedge. Thank you, Madam Chairman.

COMMISSIONER DEASON: Are you going to try to top that one?

COMMISSIONER CARTER: No. No.

CHAIRMAN EDGAR: Commissioners, before we proceed into the discussion more specifically on the first issue, any, any further discussion, comment or question at this time?

Commissioner Tew.

COMMISSIONER TEW: I have a few. Thank you. Staff, do you consider this project -- it was somewhat unclear to me in the recommendation. Do you consider this project to be a physical hedge?

MR. SLEMKEWICZ: Yes, I do.

COMMISSIONER TEW: Okay. But you don't think that all components of this project should be recovered through fuel in accordance with some of the recommendations.

MR. SLEMKEWICZ: That's correct. That's my interpretation of the hedging order as it exists.

COMMISSIONER TEW: Okay. Can you walk me through the rationale? And even if we need to refer to the wording in the hedging order, I note that it was on Page 5 of the hedging order, I think it was in Paragraph 3. And I know this was discussed a lot during the hearing, there was a lot of cross on this. I just wanted to make sure I understand sort of which categories you're putting which piece parts of the project in, if that makes any sense.

MR. SLEMKEWICZ: Okay. Well, the, you know, Issue 1A, which was a stipulated issue, covered the, you know, various costs for, you know, recovering the gas and putting it into the pipeline and other type costs that fit into the categories that are actually given in or stated in the hedging order. And, again, that was a stipulated issue and it's been previously approved. The hedging order addresses transaction costs, gains and losses from hedging and incremental O&M. And the, you know, the hedging order is, it cites examples and it's not definitive, so it leaves it open.

But as the hedging order stands, it does not address carrying costs. It doesn't specifically disallow them, but it doesn't specifically allow them. And so that's, you know, from staff's standpoint. You know, the Commission could determine on a case-by-case basis if a cost is a hedging cost, that it should be, you know, recoverable through the fuel clause. But as -- I feel as the order stands right now, the hedging order, that it's not a cost that's explicitly allowed.

COMMISSIONER TEW: So you don't believe that the hedging order did anything to change the way carrying costs had traditionally been handled and that they would be recovered through base rates?

MR. SLEMKEWICZ: That's correct. And to me fuel inventory is fuel inventory and it's properly -- the carrying costs, and that is properly includable in rate base.

CHAIRMAN EDGAR: Commissioners, other general questions or discussion before we move ahead?

Commissioner Deason.

COMMISSIONER DEASON: As you state in your recommendation, what is at issue here is the MoBay storage facility as it pertains to the, to the gas that is, that is in storage there; correct? The other facility -- can you explain the difference between the two contracts? My understanding is, one, is that FPL has actually purchased the gas and is using it for storage or other uses, and the other contract, that the base gas is part of the transactional cost of the contract; is that correct?

MR. SLEMKEWICZ: That's correct. At MoBay they own the base gas themselves, or they will own the base gas. And at Bay Gas, that's just part of the transaction cost. They in essence lease that gas or rent that gas.

COMMISSIONER DEASON: And so it's part of the transactional cost. And so, therefore, whatever cost is associated with the leasing, as you term it, the leasing of the base gas, that's in the, the contract for that, that storage contract and it is recoverable through the fuel clause; is that correct?

MR. SLEMKEWICZ: I think we assume that it's in there. I don't believe it's explicitly stated in the contract.

But the storage facility is, we would assume is going to recover the cost of the base gas that it has to keep in there.

COMMISSIONER DEASON: One would assume that if someone has an investment in base gas and they're leasing the entire facility for storage, that they're somehow including a return on that. It's probably not given away for free. That would be a prudent assumption, would it not?

MR. SLEMKEWICZ: That would be a prudent assumption.

COMMISSIONER DEASON: Yeah. Okay. So by FPL entering into the MoBay project with purchasing the base gas directly, then it becomes an issue.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Okay. I recall, I believe there was a series of questions, some of which may have originated by me, during the hearing in which the question arose as to why the decision was made to purchase the base gas. And as I recall, the general discussion, and correct me if I'm wrong, is that there was a decision made that it was more cost-effective to do so. Do you recall that or do you disagree with that?

MR. SLEMKEWICZ: No. I recall that statement.

COMMISSIONER DEASON: And you have no basis to disagree that it was more cost-effective?

MR. SLEMKEWICZ: No. Or to agree --

COMMISSIONER DEASON: Or to say otherwise.

MR. SLEMKEWICZ: You know, I can't agree or disagree with that statement.

COMMISSIONER DEASON: Okay. Thank you.

CHAIRMAN EDGAR: Commissioners, any further question or discussion at this point? No? Okay. Then we will move to further more specific discussion on the first issue, which is Issue 1B.

Mr. Slemkewicz.

MR. SLEMKEWICZ: Okay. Issue 1B addresses the method for the recovery of the base gas at the MoBay storage facility. Again, this does not affect the Bay Gas storage facility.

FPL has requested that they be allowed to recover the entire cost of the base gas at the time it is injected into the storage facility. Staff has recommended that the base gas be deferred as a regulatory asset and amortized to the fuel clause over the 15-year term of the storage agreement. And under either scenario, the -- at the end of the storage agreement, the amount of base gas, the cost would be credited back to the fuel clause under either scenario, the company's or staff's recommendation.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: Are we ready for a motion on this?

CHAIRMAN EDGAR: I don't know. Let's find out.

Commissioners, questions specifically on this issue at this time?

Commissioner Tew.

COMMISSIONER TEW: I had some clarification questions about the nonrecoverable oil. On Page 6 the discussion, I think, started about the nonrecoverable oil remains in the tank until it's periodically cleaned. Was there information in the record about how often periodically is?

MR. SLEMKEWICZ: It would -- no. But it would be based on, you know, the usage at the plants. But I would have -- well, as a guess, you know, I would have to say, you know, probably at least every two years. I mean, I'm not sure -- I don't know how large the storage tanks are, but they would be periodically cleaned and refilled.

COMMISSIONER TEW: And how is nonrecoverable oil treated? Just remind me as far as recovery. Is that expensed upfront?

MR. SLEMKEWICZ: It's expensed upfront.

CHAIRMAN EDGAR: Commissioner Arriaga.

COMMISSIONER ARRIAGA: See, the dilemma continues to come up because your basic assumption to make your recommendation in 1B is that you're comparing this base gas to base coal. And I just made two questions to you about how base coal is used. And you agreed with me that, first of all, it's not high grade and it doesn't give you the same quality of Btus when you burn it. So how can you, how can you make this comparison between natural gas as base gas and base coal? That's where my dilemma comes from.

MR. SLEMKEWICZ: It's a matter of timing. I'm looking at the base gas -- they cannot burn that base gas. They cannot use it. It has to remain in the facility for the 15-year term of the storage agreement. And that's where I look at the difference between recoverable oil or nonrecoverable oil, which is taken out on a periodic basis, and base coal, which stays there for the life of the plant or the coal pile.

COMMISSIONER ARRIAGA: Yeah. But the issue is at the end of 15 years that natural gas is as efficient and as good and as high quality as day one. Base coal is not. Therefore, the comparison to me technically is not, is not proper. That's where my doubt is. And I understand your point of view very well, but the turkey and the cat again, you know. That's my problem here.

CHAIRMAN EDGAR: Commissioners, further questions for Mr. Slemkewicz or other staff?

COMMISSIONER DEASON: Just a clarifying question.

CHAIRMAN EDGAR: Commissioner Deason.

COMMISSIONER DEASON: I think it's contained in your recommendation, but just for clarification. The, the issue of the carrying cost of the base gas for the MoBay project comes into question if we adopt your recommendation on this issue because there is an unamortized balance. If we were to adopt

FPL's position, the carrying cost is a nonissue because the investment in the, in the gas is recoverable upfront in year one; is that correct?

MR. SLEMKEWICZ: Right. Issue 1D would be moot.

COMMISSIONER DEASON: Okay.

CHAIRMAN EDGAR: Commissioner Tew.

COMMISSIONER TEW: Was that Issue 3D, John?

MR. SLEMKEWICZ: Well, if I can just quickly explain what happened. The program, the recommendation format program automatically updated the issue numbers. But they should be 1B, 1C and 1D, and then Issue 4 would be Issue 2.

COMMISSIONER TEW: Just to be clear, so on Page 11, the issue that's currently labeled as 3D, which should be 1D as I understand it, would be moot under the scenario Commissioner Deason --

MR. SLEMKEWICZ: Would be moot. Yes.

COMMISSIONER TEW: Okay.

CHAIRMAN EDGAR: Okay. Additional?

Commissioner Carter.

COMMISSIONER CARTER: I move staff on Issue 1B.

COMMISSIONER DEASON: Madam Chairman, I'm going to second the motion, and let me explain why. I believe staff's recommendation is, provides for a better matching of cost and benefits and avoids some, some potential problems of intergenerational inequities between customers.

But I want -- I second the motion. I want to make it clear though that that is no -- there's going to be -- if this motion is approved by the Commission, then there's going to be a question of the proper mechanism for recovering the carrying costs on the unamortized balance, and especially a question of cost recovery or assuming that it's somehow recovered within base rates. And I think that's a significant issue that we will need to address in a following issue. But for purposes of this, I can second the motion because I believe it does better match costs and benefits.

CHAIRMAN EDGAR: Thank you, Commissioner Deason.

Commissioners, we have a motion and a second. Is there further discussion?

Commissioner Arriaga.

COMMISSIONER ARRIAGA: I'm having heartache with this recommendation, and there is a big dilemma in my mind and it is an honest dilemma.

Now I just want you to know that when there is a doubt in my mind, I'm going to prefer at this time to err on the side of the consumer. In other words, I'm going to err on the side of the proposal made by OPC and the staff basically because there isn't clarity. But, again, as Commissioner Deason said, I reserve myself for the rest of the issues and how we're going to handle those carrying costs and all that stuff. Okay. Thank you.

CHAIRMAN EDGAR: Commissioners, further discussion?

I'm just not having heartache today. I'm feeling pretty good about things. So all in favor of the motion, say aye.

(Unanimous affirmative vote.)

Opposed? Show the motion adopted. Thank you.

Mr. Slemkewicz, we will move to Issue 1C.

MR. SLEMKEWICZ: Issue 1C addresses the recovery of the carrying costs associated with the working natural gas inventories at both MoBay and the Bay Gas storage facilities. And staff has recommended that the, you know, carrying costs not be recovered through the fuel adjustment clause. And --

CHAIRMAN EDGAR: That was a little shorter than I was expecting. Would you care to elaborate?

(Laughter.)

MR. SLEMKEWICZ: In staff's view, you know, fuel inventory is fuel inventory no matter where it is, and that fuel inventory from an accounting standpoint is normally included in rate base, and that's where staff believes that the natural -- the working gas should also be a component of rate base.

CHAIRMAN EDGAR: Thank you.

Commissioners, questions for our staff?

Commissioner Deason.

COMMISSIONER DEASON: John, I think in your description you just used the term fuel inventory, and I'm paraphrasing, but generally fuel inventory is normally included as a component of working capital and, therefore, is included in rate base and that's how we normally provide for recovery. And I guess the operative term here is "normally included." Has FPL in the past ever included working gas inventory in a gas storage facility as part of its working capital component in a rate proceeding?

MR. SLEMKEWICZ: Not in a rate proceeding, no.

COMMISSIONER DEASON: Okay. I believe in answer to a previous question you, you indicated that, and I believe this was in answer to a question from Commissioner Arriaga, that you do consider the MoBay project to be a physical hedge. It's just a question of the proper recovery of the working gas inventory.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Okay. And the reason for that is that normally fuel inventory is considered part of working capital and as part of rate base.

MR. SLEMKEWICZ: That's correct.

COMMISSIONER DEASON: Okay. Now if we believe that the project is a physical hedge, as do you, is, is there a restriction -- what discretion does the Commission have to allow recovery of these costs, given the stipulation concerning the hedging transactions as well as how that was then later incorporated into the rate stipulation?

MR. SLEMKEWICZ: Well, I believe that, you know, what you, what you would need to consider is whether or not that the carrying costs are hedging costs. If you believe, you know, if the Commission determines that they are a hedging cost and that they should be allowable through the fuel clause, you can make that decision. Because the, you know, the hedging, again, as I stated before, the hedging order just cited examples and it didn't close the door or exclude -- it didn't exclude any items per se. It generally just said these are examples of what could be in there. But carrying costs were not addressed.

COMMISSIONER DEASON: And do, do you agree that the, the MoBay project, that the reason for entering into that contract was for hedging purposes as well -- as opposed to just having a degree of inventory that would normally be associated with the proper running and dispatching of a gas generating unit?

MR. SLEMKEWICZ: Yes. I believe that to be true. And that, you know, it's -- I think, again, the main purpose was it's a physical hedge for, you know, reliability purposes. And there's always a secondary -- if you have a physical hedge, a lot of times there is a secondary hedge there on the price side. But that's more of a fallout than what the real purpose of this hedge is.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: Thank you, Madam Chairman. For staff, I'm reading here, and I think that you're in agreement with OPC that the carrying costs of this inventory should not -- should be recovered through base rates and not the fuel clause; is that correct?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER CARTER: And as such, then -- well, I won't elaborate on those issues. But it seems to me that, it makes sense to me about -- because it's historically and typically a base rate item; correct?

MR. SLEMKEWICZ: That's correct.

COMMISSIONER CARTER: And it's -- I said I wasn't going to elaborate, didn't I?

CHAIRMAN EDGAR: But you may.

COMMISSIONER CARTER: But, I mean, for the reasons enunciated it seemed to make a lot of sense to me about the basis for that. Thank you.

CHAIRMAN EDGAR: Thank you.

Commissioners, further questions?

Commissioner Arriaga.

COMMISSIONER ARRIAGA: I'm understanding that you're basing your recommendation on the fact that you believe that this is a reliability issue, that the gas is going to be used for reliability purposes.

MR. SLEMKEWICZ: That's the main purpose, but --

COMMISSIONER ARRIAGA: In other words, the physical hedge is going to be --

MR. SLEMKEWICZ: It's generally a physical hedge. But even if it's a price hedge, I do not believe, given the hedging order and normal accounting, that the fuel inventory itself and the carrying costs related to it are hedging costs.

COMMISSIONER ARRIAGA: But the problem seems to be the interpretation of the fuel inventory. You are perceiving the fuel inventory to be used for reliability purposes. I'm reading the record, and it is stated over and over and over that it is going to be used for price volatility.

Now assuming that we were to approve or deny your recommendation and approve the other, the other way around, doesn't staff have a way of checking a year from now how this gas was used either for reliability or for price volatility and true it up at that time?

MR. SLEMKEWICZ: I'd have to defer to Mr. McNulty.

MR. McNULTY: Commissioner, the only thing I could say about this is that when you, when you look at a physical hedge such as this, it may be that a utility either engages in a physical hedge primarily for price or primarily for supply reliability, but the two are intertwined. To try to extract those two from each other is, in my view, nearly impossible. You're going, you're going to get both effects when you engage in a physical hedge. So if you try to post facto look at what the effect of the hedge was, to say, oh, this year we didn't have any storms so it provided an excellent price hedge instead of a physical supply hedge, I think that, that that is not advisable. As a staff member, I would not advise that because there needs to be clarity, I think, in the process as to exactly the recoverability of the types of costs that are involved. If we're going to engage in a physical hedge, we need to send a clear signal to the utilities saying this is the location in which you get recovery.

COMMISSIONER ARRIAGA: So our, our incapacity or our inability to make that determination, let's say, a year from now puts us in a position of disincentivizing, if that's a proper word, the utility by not allowing them to take full advantage of the hedging transaction.

MR. McNULTY: I just can't extract the two, the two reasons that are here. They operate each and every year. I don't see them being extracted in any one year or how you would efficiently be able to break that out.

COMMISSIONER ARRIAGA: And I understand that. But what I'm trying to say, because we cannot differentiate and we cannot extract, we should follow the spirit of the hedging order instead of penalizing the company by not allowing them or motivating them to continue to do the proper hedging. That's what I'm trying to say. Our incapacity to do something should not go against the spirit of the hedging order which motivates the companies to hedge properly and prudently.

MR. SLEMKEWICZ: I'd like to add that, you know, we're not denying them recovery. It's just do they get it through fuel clause or do they get it through base rates?

CHAIRMAN EDGAR: And, of course, there are, I think, many orders and statutes that point out the responsibility of a monopoly utility service provider to pursue good projects, and for base rates to cover their responsibilities to pursue good projects.

Commissioners, further -- Commissioner Carter.

COMMISSIONER CARTER: Thank you, Madam Chairman.

Do these costs result in any fuel savings? I mean, I'm trying -- I don't see that anywhere.

MR. LESTER: They can result in fuel savings. I don't think there's any specific --

COMMISSIONER CARTER: No definitive statement that it does that, is there?

MR. LESTER: No. But there is a statement that, in Witness Yupp's testimony that, you know, this can produce fuel savings.

COMMISSIONER CARTER: Can?

MR. LESTER: Yes. It's not -- there is no guarantee in any given --

COMMISSIONER CARTER: Thank you, Madam Chairman.

CHAIRMAN EDGAR: Okay. Commissioner Tew and then

Commissioner Arriaga.

COMMISSIONER TEW: Just a clarification question on what Mr. Lester just said.

I'm losing my train of thought. Come back to me.

CHAIRMAN EDGAR: Okay. Commissioner Arriaga.

COMMISSIONER ARRIAGA: So if this was going to be part of the base rate, and we just stated before that the company hasn't filed in the 2005 rate case, when are they going to recover? 2010?

MR. SLEMKEWICZ: Items are added and taken away from rate base all the time and they don't come in for a rate case every time one or two items are added. That's just a normal part of the process. Rate base increases, expenses go up or down, and that's normally just covered in their, their earnings. And that's why, you know, even though they're under a stipulation, you know, we would still look at what their earnings are and if it's still in a reasonable range. And --

COMMISSIONER ARRIAGA: So there is room for recovery periodically?

MR. SLEMKEWICZ: Yes.

COMMISSIONER ARRIAGA: Without violation of the settlement agreement.

MR. SLEMKEWICZ: That's correct. When they add things to rate base, again, base rates don't go up unless they come in for a case. And as long as -- they can add things to rate base. And if revenues keep growing, they cover those items or they, you know, recover the cost of those items without a rate increase. It's only when the increase in rate base or expenses exceeds the ability of increasing revenues to cover them.

COMMISSIONER ARRIAGA: So we are in no way penalizing the company.

MR. SLEMKEWICZ: No, we're not.

COMMISSIONER ARRIAGA: Thank you.

CHAIRMAN EDGAR: Commissioner Tew.

COMMISSIONER TEW: I remembered it.

Mr. Lester, when you were responding to Commissioner Carter, I just want to be clear about what you meant as far as resulting in fuel savings. Did you mean the entire project may result in fuel savings, or did you mean the carrying costs in themselves may result in fuel savings?

MR. LESTER: I think the first, the entire project. In other words, periodically they may inject gas at, say, $7. The market price of gas may go to $9. They could withdraw that average cost $7 gas and realize a savings. That's, that's what I was thinking of. But given the volatility of gas prices, there can't be any guarantee on that.

COMMISSIONER TEW: Okay. Thank you for that distinction. Because I do think there's a great likelihood that the project will result in fuel savings, but I don't know how to say whether or not carrying costs in themselves can result in any fuel savings. Thank you.

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: Just as a follow -- that's exactly where I was going, Commissioner Tew. I was asking about whether or not the carrying costs resulted in any savings. That was the genesis of my question. Thank you.

COMMISSIONER DEASON: Madam Chairman, let me explain.

CHAIRMAN EDGAR: Commissioner Deason.

COMMISSIONER DEASON: I agree that fuel savings is a legitimate concern and certainly is a goal that we would want, we would hope would be obtained from this project, but it is not the definitive issue as to whether these costs should be included for cost recovery through the clause. It's a question of not only fuel savings is an issue, but it's a question of price volatility. And if it mitigates price volatility, doesn't that meet the requirements of the hedging order?

MR. McNULTY: Yes, it does, Commissioner.

CHAIRMAN EDGAR: Commissioners, how about we take ten. All right? I could use some contemplation. Always a good thing. I'm a strong believer in contemplation. So we're going to take a short break and a stretch, and we'll come back in ten minutes.

(Recess taken.)

CHAIRMAN EDGAR: We will go back on the record.

Thank you all. It feels good to have a stretch on this cold morning, although it's warm in here. Thank you.

COMMISSIONER CARTER: It's too warm in here.

CHAIRMAN EDGAR: Oh, Katrina and I think it's pretty good.

COMMISSIONER CARTER: Oh, I stand corrected. It's fine.

CHAIRMAN EDGAR: Okay. We have had some discussion on Item 1C. I think we probably need to have a little further discussion. And then we'll see if we get ourselves in the posture where we're ready to proceed with a motion.

I guess let me start out this way. Are there any additional questions during the break that have come to mind that would like to be posed to staff?

Okay. Well, then if I may, just a couple of comments. As Mr. McNulty said to us a few minutes ago, and I am putting this in my own words, but what I think was the essence of it is, you know, it's all connected. As with almost everything in life, it's all connected. And if you, you know, pull one string, it touches and pushes and pulls on a variety of other items. And, and that's kind of where, where I'm coming from when I think through this issue.

I also note that there are a number of actions that this Commission has taken during the two years that I've been here to minimize disruption or to attempt to put in place policies to help minimize the potential for disruption, and supply reliability falls into that, I think. We've also looked at trying to increase the potential for stronger reliability and hardening of the infrastructure. We've also looked at fuel diversity, a number of things. And, of course, there again it's all connected.

I also feel very strongly just from my own perspective that the hands of this Commission are really only tied by statute, and that we certainly need to look to prior orders, as we do every time we sit in these chairs, but that costs can be reviewed and should be reviewed. And if with a full review costs are found to be prudent by this Commission, our hands are not tied as to our decisions as to how they are dealt with from an accounting standpoint.

I do believe very strongly that the burden is on a utility as part of the regulatory compact, as part of being a monopoly service provider to pursue good projects, projects that are good for the state as a whole, projects that are good for the utility, projects that are good for consumers, projects that increase reliability and efficiency. In this instance to me, and this is just from my own perspective, these costs to me seem to be more in line with what I think of as typical base rate costs. We're talking about reliability of supply helping to prevent supply disruptions. There is -- I can see a potential scenario where there could be a cost savings, but that is certainly not guaranteed. I can certainly see a number of other scenarios where there would not be cost savings, and perhaps this project will be a contributor to a variety of benefits as I've tried to kind of discuss. Yes, gas that is pulled out for whatever reasons, that is needed to be pulled out for whatever reasons will need to be replaced. And, in general, gas costs are probably not going, you know, way down. I wish they were. It's that SUV that I've got parked out front. I really wish they were.

So, again, I see it as a base rate item that will be recovered, it will be recovered, but just not passed through the fuel clause. And that's kind of my thoughts after some contemplation additionally, and I welcome any further discussion.

Commissioner Tew.

COMMISSIONER TEW: I guess I'll say that I agreed with what Commissioner Deason said, that this project mitigates price volatility in his question to staff. And I do believe that the spirit of the hedging order allows for recovery of those projects that attempt to mitigate price volatility by allowing recovery of both gains and losses associated with those hedges. However, I don't believe that carrying costs in themselves, although they are reasonable costs to be recovered -- and I think that as staff has pointed out, those would be recovered under their recommendation, just not in the way that the company has requested -- I don't believe that they themselves serve to mitigate price volatility.

And, further, I don't believe that the hedging order alone gives direction to us to vary that traditional treatment of carrying costs. So with that said -- I also should say that I don't intend with the vote that we'll eventually take to discourage these types of projects. And I, too, emphasize that a vote in favor of the staff rec doesn't disallow, does not disallow carrying costs. It just calls for a different method of recovery, as I said earlier. And I think that it is important to send a strong message to FPL that they should continue to pursue these kinds of projects in whichever way they're recovered. With that said.

CHAIRMAN EDGAR: Thank you, Commissioner Tew.

Commissioners, further discussion or questions?

Commissioner Deason.

COMMISSIONER DEASON: Just a comment. I don't necessarily disagree with what's been said. I don't necessarily find a lot of fault with staff's recommendation. I just don't agree with it. Okay? And, Commissioner Tew, with all due respect, I think that by following staff's recommendation, you may actually have the unintended consequence of giving a disincentive to enter into these types of, of contracts. I think the impetus for this contract was to -- was consistent with the, the spirit and the letter of the hedging order. And if mitigation of price volatility is one of the goals of the hedging, the hedging order, I think this project meets that requirement.

I do agree that everything, Madam Chairman, everything is intertwined. And I do agree with staff's analysis; you can't really segregate out the amount of cost associated with price volatility as opposed to reliability of supply. It just -- to me the impetus for the project was mitigation of price volatility, and the added bonus was it increases reliability.

I suppose you could look at it the other way, that it was the prudent thing to do from a reliability standpoint, and the added benefit was it could mitigate price volatility. So I guess it's kind of how you view what the purpose of entering into this contract was.

I hope that if we do follow staff's recommendation, that it does not have the disincentive to companies, not only FPL but other companies that may find themselves in similar situations, I hope it does not provide as a disincentive. But the fact remains, and it cannot be ignored, that there's a substantial amount of investment and this, the gas is sitting there in the facility. And the only way to achieve the hedge is you have to buy the gas upfront to have the physical hedge. That by definition has to be the case. And whenever you make that degree of an investment upfront, there's going to be significant carrying costs associated with that. Carrying costs for the working gas, which is the subject of this issue, as well as carrying costs associated with the base gas, which, as we've already determined, is going to be spread over 15 years.

So, Commissioner, I don't think there's a right or wrong answer. It's just an answer that I'm more comfortable with and I think sets the tone and I think has the, has the potential for creating greater customer savings and protecting customers from fluctuations and volatilities associated with the commodity price of gas. So for those reasons, I'm going to disagree with staff's recommendation. But I certainly see merit in the recommendation, and so it's not a criticism of the recommendation. I just view it a little differently.

CHAIRMAN EDGAR: Thank you, Commissioner Deason.

Commissioner Arriaga.

COMMISSIONER ARRIAGA: Commissioner Deason, the first day I met you personally I told you that one of the things that I admire in you was that you are usually the voice of reason. And I also told you that I admire your capacity to properly express what I am sometimes limited in saying. And I appreciate what you just said because you just put into proper context the message that I've been trying to send since I sat here this morning. So I'm going to endorse every exact word and comment that you just made. Thank you.

CHAIRMAN EDGAR: Thank you. Commissioner Arriaga, it seems like you're sending a lot of messages.

(Laughter.)

Okay. Commissioners, further, further discussion?

Clearly, we are of many minds always, but certainly on this very specific issue that is before us. If -- I'm ready to move forward. But if for whatever reason one of you needs some additional time or some additional discussion, we can certainly do that as well.

Commissioner Deason, as always, very articulately has discussed some of the rationale for two different ways of looking at this issue. And I almost always agree with Commissioner Deason, but every once in a while we do look at things a little differently, and I think this may be one of them.

COMMISSIONER DEASON: That's what makes this process so great, Madam Chairman.

CHAIRMAN EDGAR: Agreed. So what is your pleasure?

COMMISSIONER CARTER: Madam Chair, I move staff's recommendation.

COMMISSIONER TEW: Second.

CHAIRMAN EDGAR: Commissioners, we have a motion and a second. Is there further discussion? Okay. All in favor of the motion, say aye.

COMMISSIONER TEW: Aye.

COMMISSIONER CARTER: Aye.

CHAIRMAN EDGAR: Aye.

Opposed?

COMMISSIONER ARRIAGA: Nay.

COMMISSIONER DEASON: Nay.

CHAIRMAN EDGAR: That sounds like a three to two in favor of the motion to me. And with that, Commissioners, I thank you for your thoughtful discussion.

And we will move on to the next issue, which is 1D.

MR. SLEMKEWICZ: Issue 1D addresses the recovery of the carrying costs of the unamortized balance of MoBay Gas. Based on the decision in Issue 1B to defer that amount and amortize it, the staff is recommending that the, the carrying costs associated with those unamortized amounts of base gas for the MoBay storage facility is properly recovered through, in base rates. And this does not affect the Bay Gas facility because there is no base gas that is owned by Florida Power & Light.

CHAIRMAN EDGAR: Thank you.

Commissioners, questions or discussion on Issue 1D? No?

COMMISSIONER DEASON: I think it's probably been adequately discussed by the previous two, previous two issues.

CHAIRMAN EDGAR: Commissioner Deason, I agree. But as always, if we'd like to talk some more, I am glad to allow it. So if that is the case, then is there a motion?

COMMISSIONER CARTER: Madam Chairman, I move staff's recommendation.

CHAIRMAN EDGAR: Thank you. Is there a second?

COMMISSIONER TEW: Second.

CHAIRMAN EDGAR: Commissioners, there is a motion and a second. Is there further discussion? Seeing none, all in favor, say aye.

COMMISSIONER TEW: Aye.

COMMISSIONER CARTER: Aye.

CHAIRMAN EDGAR: Aye.

Opposed?

COMMISSIONER DEASON: Nay.

COMMISSIONER ARRIAGA: Nay.

CHAIRMAN EDGAR: That sounds again like a three to two to me in favor of the motion.

And so we will move to Issue 2, which is to close the docket after -- oh, I'm sorry, Mr. Slemkewicz. You can go ahead and lay it out for us.

MR. SLEMKEWICZ: Okay. Well, it is just to, you know, close the docket. It is a new issue that was not in the prehearing order but it's appropriate for this docket.

CHAIRMAN EDGAR: Thank you. Commissioners, is there a motion?

COMMISSIONER CARTER: Move staff.

COMMISSIONER DEASON: Second.

CHAIRMAN EDGAR: All -- discussion? No? All in favor of the motion, say aye.

(Unanimous affirmative vote.)

Opposed? Show it adopted. Thank you.

Commissioners, that brings us to the next docket, which is 060001 regarding the fuel and purchased power cost recovery and the generating performance incentive factor. Are we ready to move forward? Okay. Then we'll give our staff a moment to get settled. And then, Ms. Bennett, is there anything else we need to do before we move into the next docket?

MS. BENNETT: No, Madam Chair.

CHAIRMAN EDGAR: Okay. Then when Mr. Matlock is ready. Are you ready? You can take a minute if -- okay. Then go right ahead, please.

MR. MATLOCK: Good morning. I'm Sid Matlock of Commission staff. Because of performance declines in recent years by one utility and apparent performance declines among some of the units for the utilities, the Office of Public Counsel has petitioned for modification of the GPIF reward and penalty criteria. The generating utilities have countered that performance declines are not measured in the ways presented by OPC's witness, that the present reward and penalty criteria are applied as they were intended to be applied, and that the rewards achieved by the generating utilities were achieved -- or when achieved reflect fuel cost savings with which they are associated.

Staff has reviewed the arguments presented by OPC and the utility arguments and recommends that the present criteria not be modified or amended.

Staff would be glad to answer questions regarding its recommendation.

CHAIRMAN EDGAR: Thank you. Commissioners, questions regarding Issue 21? Okay. I'm going to go ahead and look to my left because I can't tell if that's a yes or no regarding questions. Are there questions?

COMMISSIONER ARRIAGA: I have no questions.

CHAIRMAN EDGAR: Okay. Commissioner Arriaga.

COMMISSIONER ARRIAGA: No. I have no questions.

CHAIRMAN EDGAR: Oh, no questions. Okay.

Commissioner Tew.

COMMISSIONER TEW: I have a clarification question about the recommendation statement. And this may have been cleared up previously, I don't know. But in that last sentence of the recommendation statement where it says "Gift's," is that supposed to be GPIF's?

MR. MATLOCK: Yes, ma'am.

COMMISSIONER TEW: Okay. Thank you.

COMMISSIONER DEASON: Is that a Freudian slip there?

COMMISSIONER CARTER: Let's hope not.

(Laughter.)

CHAIRMAN EDGAR: Commissioners, any other questions or discussion? No? Okay.

I had some concern when I listened to the discussion at the hearing and also reviewed some of the information after the hearing that, that some of the changes that were being suggested, and I'm always welcome to consider suggestions for change, but that in this instance those suggestions would effectively eliminate future rewards or the potential to receive a future reward. And I stand by my previous comments, but I also do believe in incentives for performance, or at least in some instances.

So the, the proposal that was before us just didn't completely make sense to me. Quite frankly, it seemed a little arbitrary. So I'm not really comfortable just for myself with the proposal that was put forth to change the current program, but yet I recognize that that program has been in place for a very long time. And perhaps it is appropriate to ask our staff at some point in whatever way in the future to just take a good look at the GPIF program in its totality and maybe there are some other changes that would be good. I don't know. I don't presuppose the result of that review, but I'd just throw that out.

Commissioners, any, any other comments?

Commissioner Deason.

COMMISSIONER DEASON: Madam Chairman, I agree with what you say. I think the GPIF has worked well over the years. That's not to say though that it could not be improved, particularly with the changes that occur in economics and technologies and things. Potentially it could. I just don't think based upon this record that we have a case to change it. But there -- you know, with your direction, Madam Chairman, and perhaps staff can, can engage in further review and, and enhance and make better a, a process that works well. That may be beneficial. But based upon the record that we have in front of us right now, I'm not convinced that we need to make the change, the specific changes as proposed.

CHAIRMAN EDGAR: Thank you.

Commissioners, any other comments? No?

Okay. Then I think we are in a posture where we're ready to take a motion.

COMMISSIONER DEASON: Madam Chairman, I can move staff's recommendation in its entirety.

COMMISSIONER CARTER: Second.

CHAIRMAN EDGAR: Thank you. We have a motion and a second. And I believe, Commissioner Deason, that includes Issue 21, Issue 22 and Issue A; is that correct?

COMMISSIONER DEASON: That's correct. All issues.

CHAIRMAN EDGAR: Okay. Commissioners, any further discussion? Seeing none, all in favor of the motion, say aye.

(Unanimous affirmative vote.)

Opposed? Show it adopted.

MS. BENNETT: Madam Chair?

CHAIRMAN EDGAR: Ms. Bennett.

MS. BENNETT: The Issue 22 recommendation is that if you were to adopt the Issue 21, that there be workshops. So I'm not sure that Issue 22 should be approved as staff recommends. Actually Issue 22 is moot.

COMMISSIONER DEASON: Well, Madam Chairman, I think staff's recommendation basically says that, does it not, that it's moot? If we -- so that was the spirit of the motion. But to clarify, I could amend the motion to just indicate that, that -- is it Issue 22 is moot?

MS. BENNETT: That's correct.

COMMISSIONER DEASON: So just for clarification, if that's needed, I'm certainly willing to do that.

CHAIRMAN EDGAR: Okay. Thank you, Commissioner Deason. And that was, again, certainly my understanding. And I think that, and I'm seeing nods in the affirmative, that I'll go ahead and state for the benefit of the transcript. So I think we are in good shape and we have addressed all issues in this docket. Ms. Bennett, is that your understanding as well?

MS. BENNETT: It is my understanding that we are, have completely discussed and completed the issues.

CHAIRMAN EDGAR: Okay. Then we are about to adjourn. Are there any comments for the good of the order?

COMMISSIONER CARTER: Madam Chairman?

CHAIRMAN EDGAR: Commissioner Carter.

COMMISSIONER CARTER: I think that what we've dealt with this morning was a continuation of a long and drawn-out process, but I do hope that staff will take the comments in terms of how do we incentivize, you know, this process going forward? Secondly, how do we provide, you know, additional information in terms of how we deal with the GPIF and other -- and maybe somehow or another we can do it in a nonadversarial way where staff can bring on the different and disparate parties together so they can provide for us an opportunity to what we deal with. We've dealt with some significant issues here, but a lot of what we dealt with was based upon the facts as presented. And I would hope that, you know, going forward -- obviously during your dynamic leadership we should be able to do that, and I'm really looking forward to having those discussions. Thank you.

CHAIRMAN EDGAR: Thank you, Commissioner Carter. I appreciate that. And recognizing that we will back for another fuel docket next November, I think to have further discussion on some of these issues prior to that time will be a very good thing. Okay. Then we are adjourned.

(Hearing adjourned at 10:56 a.m.)

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

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 12th DAY OF DECEMBER, 2006.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Commission Reporter
(850) 413-6734

Comprehensive Exhibit List for Entry into Hearing Record				Entered
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	
Staff				
1.		Exhibit List- 1	Comprehensive Stipulated Exhibit List	
2.		Staff Consolidated Exhibit - 1	FPL'S Responses to Staff's 4th Set of Interrogatories (Nos. 9-47) and 7th Set of Interrogatories (Nos. 67-69); GULF's Responses to Staff's 4th Set of Interrogatories (Nos. 14-29); TECO's Responses to Staff's 4th Set of Interrogatories (Nos. 25-33) which Includes Responses to Staff's 1st Set of Data Requests (Nos. 1-9); PEF's Responses to Staff's 6th Set of Interrogatories (Nos. 22-28); Transcript of the October 18, 2006, Panel Deposition of Carols Aldazabal, Joann Wehle & Benjamin Smith.	
3.		CONFIDENTIAL Staff Exhibit – 2	GULF's Responses to Staff's 4th Set of Interrogatories (No. 16)	
Testimony Exhibit List				
FPL				
4.	G. Yupp	(GJY – 3)	Petition to Recover Natural Gas Storage Costs	
5.	G. Yupp	(GJY – 4)	Gas Storage Costs	
OPC				
6.	P. Merchant	(PWM – 1)	Curriculum Vitae	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 1
Company/ FPSC Staff
Witness: Exhibit List-1
Date: 11/06-08/06

Comprehensive Exhibit List for Entry into Hearing Record				Entered
Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	
7.	P. Merchant	(PWM – 2)	Gulf Power Company Rate Case MFRs – Docket No. 010949-EI – Schedule of Fuel Inventory	

HEARING EXHIBITS				
Exhibit #	Witness	Counsel	Description	Moved In/Due Date of Late Filed
8.				
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EXHIBIT NO. __________

DOCKET NO: 060362-EI

WITNESS: VARIOUS

PARTY: FLORIDA POWER & LIGHT CO.
PROGRESS ENERGY FLORIDA
TAMPA ELECTRIC COMPANY
GULF POWER COMPANY
FLORIDA PUBLIC UTILITIES

DESCRIPTION: COMPOSITE EXHIBIT OF STIPULATED NON-CONFIDENTIAL DOCUMENTS:

1. FLORIDA POWER AND LIGHT'S RESPONSES TO STAFF'S 4TH SET OF INERROGATORIES (NOS. 9-47), AND FLORIDA POWER AND LIGHT'S RESPONSES TO STAFF'S 7TH SET OF INTERROGATORIES (NOS. 67-69);

2. GULF POWER COMPANY'S RESPONSES TO STAFF'S 4TH SET OF INTERROGATORIES (NOS. 14-29)

3. TAMPA ELECTRIC COMPANY'S RESPONSES TO STAFF'S 4TH SET OF INTERROGATORIES (NOS. 25-33);

4. PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S 6TH SET OF INTERROGATORIES (NOS. 22-28);

5. TRANSCRIPT OF PANEL DEPOSITION OF CARLOS ALDAZABAL, JOANN WEHLE AND BENJAMIN SMITH DATED OCTOBER 18, 2006.

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 2
Company/ FPSC Staff
Witness: Staff Consolidated Exhibit-1
Date: 11/06-08/06

Q.

During a May 30, 2006 conference call Commission staff raised a concern regarding processing plants. Some processing plants had operational problems during the 2005 Gulf of Mexico hurricanes which prevented or interrupted the flow of natural gas into the Gulfstream pipeline.

(A) Does the gas from MoBay storage enter a processing plant prior to entering the Gulfstream pipeline?

(B) If the answer is yes, could difficulty with the processing plants during or after a storm interfere with the use of MoBay storage as a supplier of gas to Gulfstream?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 1 dated 06/21/2006.

Q.

Regarding MoBay's storage as a temporary alternative to off-shore gas, please explain the series of steps that would occur in getting gas from MoBay to Gulfstream and FGT if Zone 3 gas becomes unavailable during a storm.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 2 dated 6/21/2006.

Q.

If FPL did not participate in the MoBay storage project but continued to pursue their current projects to enhance reliability, what is the probability of FPL not meeting its firm retail load commitments? Please identify any studies that support this response.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data No. 4 dated 6/21/2006.

Q.

How reliable will MoBay's facilities be if the Mobile area is hit by a hurricane? Please explain.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 5 dated 06/21/2006.

Q.

Please refer to paragraph 15 on page 7 of FPL's original petition in response to this interrogatory. Please provide a schedule quantifying the carrying cost associated with the inventory at Bay Gas as projected for 2006.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 6 dated 06/21/2006.

Q.

As an alternative to MoBay, did FPL consider expanding its storage participation with Bay Gas? Please explain if it was considered, why FPL chose not to pursue expansion and if it was not considered, why it wasn't considered.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 7 dated 06/21/2006.

Q.

Please provide a brief history of FPL's involvement with Bay Gas.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 2 dated 08/25/2006.

Q.

What are the fees or charges that FPL pays to Bay Gas for storage of natural gas? Please state and explain each charge.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 3 dated 08/25/2006.

Q.

Compare the fees and charges listed in 16 above to those proposed to be charged by MoBay. In responding to this subsection please identify if Bay Gas charges:

(A) a monthly storage reservation charge

(B) a charge for base gas

(C) charges for injection and withdrawal

(D) an insurance charge.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 3 dated 08/25/2006.

Q.

For each fee or charge listed in response to question 16 and 17 above, how is the fee or charge currently being recovered (in base rates, the fuel clause or some other recovery mechanism)? For each fee or charge recovered through the fuel clause, what is FPL's rationale or justification for including the fee or charge in the fuel adjustment clause?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 3 dated 08/25/2006.

Q.

For each fee or charge that Bay Gas charges FPL for storage service, how is the fee or charge reported in the A schedules?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 5 dated 08/25/2006.

Q.

For each fee or charge that Bay Gas charges FPL for storage service, how was it reported in the projection testimony used to set the fuel factor in 2005 and 2006?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 6 dated 08/25/2006.

Q.

Does FPL pay for base gas at Bay Gas? Please explain.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 7 dated 08/25/2006.

Q.

Please provide a schedule showing FPL's estimate of its annual cost of participating in the MoBay Storage Project. Please provide any support that FPL believes proves this annual cost is a reasonable cost.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 8 dated 08/25/2006.

Q.

For gas storage carrying costs discussed in both FPL's petition and staff's original recommendation dated August 3, 2006, estimate the annual carrying costs which would flow through the fuel clause. When responding to this request, identify separately the anticipated carrying costs for Bay Gas, for MoBay and the rate of return on the unamortized balance of the base gas.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 9 dated 08/25/2006.

Q.

Based upon FPL's original petition and using the accounting and recovery treatment suggested by staff in its August 3, 2006 recommendation to the Commission, provide your best estimate of the incremental increase to the fuel factor for 2008 and for 2009 based upon recovery of all costs of the Mobay contract.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 10 dated 08/25/2006.

Q.

It is staff's understanding that the in-service date for Phase I of the MoBay Storage Hub is April 2008. Please provide a timeline for the project showing the latest date by which FPL believes it must obtain FPSC approval. Please discuss how delays in regulatory approval for FPL's participation in the MoBay project will affect the following:

(A) FPL's decision whether to continue with the MoBay project

(B) MoBay's ability to meet the April 2008 in-service date

(C) FPL's costs of participating in the MoBay project

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 11 dated 08/25/2006.

Q.

For purposes of responding to this question, assume that there is a distinction between hedging for price volatility which protects the utility and its customers from an unstable market and hedging for supply reliability which protects the utility and its customers against disruptions of fuel supplies caused by strikes, acts of nature, etc. Please refer to Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket 011605-EI. Does this order authorize physical hedges for supply reliability? Please explain.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 12 dated 08/25/2006.

Q.

What is FPL's definition of physical hedging? Please provide examples.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 13 dated 8/25/2006.

Q.

Please refer to pages 6 and 7 of FPL's petition and to page 3 of Gerry Yupp's affidavit, attached to FPL's petition. How is inventory carrying costs a hedging transaction cost? Please include any reference to orders, etc.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 14 dated 08/25/2006.

Q.

Does FPL believe that stored natural gas is fuel inventory? Please explain and include in the explanation comparisons/contrasts with heavy oil stored in tanks, on site or off site, and coal piles, on site or off site.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 15 dated 08/25/2006.

Q.

For each fossil fuel FPL burns, at what point in the transportation chain does it take ownership?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 16 dated 08/25/2006.

Q.

For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of FPL?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 17 dated 8/25/2006.

Q.

For off-site storage of fossil fuel (heavy oil and coal), identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale, please cite applicable rules or orders.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 18 dated 08/25/2006.

Q.

For on-site storage of fossil fuel (heavy oil and coal), identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale, please cite applicable rules or orders.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 19 dated 08/25/2006.

Q.

If storage costs are recovered through the fuel clause, for the delivered price of that fuel, detail whether you have considered storage costs to be commodity, transportation or hedging costs.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 20 dated 08/25/2006.

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Interrogatory No. 35

Q.

If fuel carrying costs are applicable to any fuel storage, indicate whether those costs are recovered through the fuel clause or base rates. Is there a difference in treatment of carrying costs for fuel stored on-site vs. off-site? What is your rationale for any recovery of fuel inventory carrying cost through the fuel clause?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 21 dated 08/25/2006

Q.

How may barrels of heavy oil are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 22 dated 08/25/2006.

Q.

How many MMBtu's of heavy oil are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 23 dated 08/25/2006.

Q.

How many tons of coal are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 24 dated 08/25/2006.

Q.

How many MMBtu's of coal are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 25 dated 08/25/2006.

Q.

How many barrels of light oil are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 26 dated 08/25/2006.

Q.

How many MMBtu's of light oil are in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 27 dated 08/25/2006.

Q.

If FPL would have had 6,000,000 decatherms in storage in 2005 and used the supply in storage following Hurricane Katrina, how soon after using the supply in storage would it have replenished the supply? How would it have known that the timing was right?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 28 dated 08/25/2006.

Q.

When FPL reports purchases of fuel on its monthly Schedule A-5, does it report any units that are not physically located at an FPL power plant or at Plant Scherer or St. Johns River Power Park? Please distinguish between fuel that is at a non-FPL-power-plant location and fuel that is in transit from a non-FPL-power-plant location.

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 29 dated 08/25/2006.

Q.

Do the quantities of oil and coal reported as purchases on Schedule A-5 differ from the quantities reported on the FPSC 423 Forms?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 30 dated 08/25/2006.

Q.

If FPL receives heavy oil at the Sanford plant to be burned at Sanford Unit #3, through a terminal in Jacksonville, FL, does FPL report the oil in its inventory when it is on the way to the terminal, at the terminal, on the way from the terminal to Sanford, or only after the oil is received at the Sanford Plant?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 31 dated 08/25/2006.

Q.

If FPL receives heavy oil at the Cape Canaveral plant to be burned at Cape Canaveral Units #1 or #2, through the Port Canaveral Terminal, does FPL report the oil in its inventory when it is on the way to the terminal, at the terminal, on the way from the terminal to the Cape Canaveral plant, or only after the oil is received at the Cape Canaveral Plant?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 32 dated 08/25/2006.

Q.

Is the Boca Grande terminal in FPL's rate base?

A.

FPL's answer to this interrogatory is as stated in its response to Staff's First Data Request No. 33 dated 08/25/2006.

Q. 1 Please provide a complete copy of FPL's contract or agreement with Bay Gas storage.

A. The documents responsive to this request are confidential and are being provided with FPL's Notice of Intent to Seek Confidential Classification.

Q. 2 Please provide a brief history of FPL's involvement with Bay Gas.

A. FPL engaged in several interruptible storage arrangements with Bay Gas beginning in 2000. These were short-term transactions that FPL utilized to help reduce fuel price volatility and ensure adequate supply. On November 1, 2003, FPL entered into a four-year firm storage agreement with Bay Gas for 1,000,000 MMBtu of storage capacity. On July 19, 2005, FPL executed a five-year firm storage agreement with Bay Gas for 2,000,000 MMBtu of storage capacity beginning on July 1, 2007. This 2005 agreement replaces FPL's 2003 four-year agreement with Bay Gas. The new agreement runs through June 30, 2012.

Q. 3A. What are the fees or charges that Bay Gas to charges FPL for storage of natural gas? Please explain each charge.

B. Compare the fees and charges listed in A above to those proposed to be charged by MoBay. In responding to this subsection please identify if there:

(i) is a monthly storage reservation charge

(ii) is a charge for base gas

(iii) are charges for injection and withdrawal

(iv) is an insurance charge.

C. For each fee or charge listed in A and B above, how is the fee or charge currently being recovered (in base rates, the fuel clause or some other company mechanism)? For each fee or charge recovered through the fuel clause, what is FPL's rationale or justification for including the fee or charge in the fuel adjustment clause.

A. Bay Gas charges FPL a monthly storage reservation fee and injection/withdrawal fees. The monthly storage reservation fee is charged on FPL's contractual storage capacity. There are two types of injection/withdrawal fees: (1) a percentage fuel retention charge on injected volumes and, (2) a dollar per MMBtu commodity charge on all injected and withdrawn volumes. Injection/withdrawal charges are designed to compensate the storage provider for fuel used in the compression process and operation and maintenance expenses.

B. MoBay will charge FPL a monthly storage reservation fee on its contractual storage capacity (working gas) and injection/withdrawal fees. Base gas and insurance charges are not stated separately in the Bay Gas contract, so Bay Gas recovers these charges through the monthly storage reservation fee. For the MoBay contract, base gas and insurance charges were broken out separately at FPL's request, so that FPL will have the option to self-provide if it can do so at a lower cost.

C. Currently, all of the fees that FPL pays to Bay Gas are recovered through the fuel clause. FPL considers these fees to be gas transportation related charges and/or hedging-related costs. FPL has included results associated with the storage transactions in its annual hedging filing beginning with the first filing in April, 2003.

Q. 4 Staff skipped Question No. 4.

Q. 5 For each fee or charge that Bay Gas charges FPL for storage service, how is the fee or charge reported in the A schedules?

A. The monthly storage reservation fee and injection/withdrawal fees are reported in the total cost of natural gas on schedule A3 each month.

Q. 6 For each fee or charge that Bay Gas charges FPL for storage service, how was it reported in the projection testimony used to set the fuel factor in 2005 and 2006?

A. FPL includes the monthly storage reservation fee for Bay Gas in its annual projections for the cost of natural gas. This fee is added into FPL's monthly projection for natural gas expenses. FPL did not attempt to estimate the variable costs it would incur for the injection/withdrawal of natural gas during these projected periods. Therefore, estimated injection/withdrawal fees are not included in FPL's annual projections but instead appear in the fuel true-up for each annual period.

Q. 7 Does FPL pay for base gas at Bay Gas? Please explain.

A. See response to Data Request 3B.

Q.8 Please provide a schedule showing FPL's estimate of its annual cost of participating in the MoBay Storage Project. Please provide any support that FPL believes proves this annual cost is a reasonable cost.

A. The schedule showing FPL's estimated annual cost for participating in the MoBay Storage Project is confidential and is being provided with FPL's Notice of Intent for Confidential Classification. Please see FPL's confidential response to Late-Filed Data Request No. 7, Page 2 of 3 filed on June 16, 2006, which provided a table that detailed FPL's storage alternatives from five potential suppliers. This table demonstrates that the MoBay charges compare favorably to the other available alternatives and are reasonable.

Q. 9 For gas storage carrying costs discussed in both FPL's petition and staff's original recommendation, estimate the annual carrying costs which would flow through the fuel clause. When responding to this request, identify separately the anticipated carrying costs for Bay Gas, for MoBay and the rate of return on the unamortized balance of the base gas.

A. The carrying costs on inventory for BayGas and MoBay are projected to be $983,503 and $5,904,092, respectively. These calculations, as well as the base gas amortization are provided on the attached pages.

MONTH	BAY GAS INVENTORY(1)	AVERAGE BALANCE	RETURN ON INVESTMENT(2)
Dec-05	13,962,172		
Jan-06	11,566,247	12,764,210	125,148
Feb-06	6,031,630	8,798,939	86,270
Mar-06	8,445,514	7,238,572	70,971
Apr-06	7,676,181	8,060,848	79,033
May-06	7,947,985	7,812,083	76,594
Jun-06	7,947,985	7,947,985	77,927
Jul-06	7,947,985	7,947,985	77,927
Aug-06	7,947,985	7,947,985	77,927
Sep-06	7,947,985	7,947,985	77,927
Oct-06	7,947,985	7,947,985	77,927
Nov-06	7,947,985	7,947,985	77,927
Dec-06	7,947,985	7,947,985	77,927
2006 TOTAL RETURN			983,503

Note 1: Actual gas inventory balances from December 2005 through May 2006.
Balances for the remainder of the year use the May 2006 balance.

Note 2: *The pretax cost of capital used in the return on investment calculation is 11.7655%*
consistent with the cost of capital used in the cost recovery clauses return on investment calculations.

MONTH	MOBAY INVENTORY(1)	AVERAGE BALANCE	RETURN ON INVESTMENT(2)
Dec-05	84,077,940		
Jan-06	69,412,200	76,745,070	752,453
Feb-06	36,183,888	52,798,044	517,663
Mar-06	50,681,514	43,432,701	425,840
Apr-06	46,046,496	48,364,005	474,189
May-06	47,708,490	46,877,493	459,614
Jun-06	47,708,490	47,708,490	467,762
Jul-06	47,708,490	47,708,490	467,762
Aug-06	47,708,490	47,708,490	467,762
Sep-06	47,708,490	47,708,490	467,762
Oct-06	47,708,490	47,708,490	467,762
Nov-06	47,708,490	47,708,490	467,762
Dec-06	47,708,490	47,708,490	467,762
2006 TOTAL RETURN			5,904,092

Note 1: Bay Gas inventory percentages applied to MoBay storage capacity for illustrative purposes.

Note 2: The pretax cost of capital used in the return on investment calculation is 11.7655%
consistent with the cost of capital used in the cost recovery clauses return on investment calculations.

INITIAL COST:	32,565,000
PROJECT LIFE:	15
CLAUSE PRETAX RETURN	11.7655%
DISCOUNT RATE	8.0000%

	EXPENSE	BALANCE	RETURN	YEARLY COST	PRESENT VALUE
0	0	32,565,000		0	0
1	2,171,000	30,394,000	3,703,721	5,874,721	5,439,556
2	2,171,000	28,223,000	3,448,292	5,619,292	4,817,637
3	2,171,000	26,052,000	3,192,863	5,363,863	4,258,007
4	2,171,000	23,881,000	2,937,434	5,108,434	3,754,851
5	2,171,000	21,710,000	2,682,005	4,853,005	3,302,873
6	2,171,000	19,539,000	2,426,576	4,597,576	2,897,252
7	2,171,000	17,368,000	2,171,147	4,342,147	2,533,601
8	2,171,000	15,197,000	1,915,718	4,086,718	2,207,926
9	2,171,000	13,026,000	1,660,289	3,831,289	1,916,598
10	2,171,000	10,855,000	1,404,860	3,575,860	1,656,315
11	2,171,000	8,684,000	1,149,431	3,320,431	1,424,076
12	2,171,000	6,513,000	894,002	3,065,002	1,217,154
13	2,171,000	4,342,000	638,573	2,809,573	1,033,074
14	2,171,000	2,171,000	383,144	2,554,144	869,586
15	2,171,000	0	127,715	2,298,715	724,651
15	-32,565,000	0	0	-32,565,000	-10,265,846
TOTAL	0		28,735,763	28,735,763	27,787,312

Q. 10 Based upon your petition and using the accounting and recovery treatment suggested by staff in its August 3 recommendations, provide your best estimate of the incremental increase to fuel factor for 2008 and for 2009 based upon recovery of all costs of the MoBay contract.

A. The incremental increase to the fuel factor in 2008 and 2009 is approximately $0.22 on a Residential 1,000 kWh Bill. This estimate was calculated using 2007 projected sales as a proxy for 2008 and 2009. This estimate does not reflect any offset for fuel cost savings that FPL may be able to achieve as a result of the MoBay storage capacity. Those savings could be substantial, but are dependent upon specific factual circumstances that cannot be projected in advance.

Q. 11 It is staff's understanding that the in-service date for Phase I of the MoBay Storage Hub is April 2008. Please provide a timeline for the project showing the latest date by which FPL believes it must obtain FPSC approval. Please discuss how delays in regulatory approval for FPL's participation in the MoBay project will affect the following:

- **FPL's decision whether to continue with the MoBay project**
- **MoBay's ability to meet the April 2008 in-service date**
- **FPL's costs of participating in the MoBay project**

A. The latest date that FPL can obtain FPSC approval without putting the contract at risk is September 29, 2006. Under the current extension negotiated with MoBay, FPL has until September 29, 2006 to receive FPSC approval. This extension was negotiated assuming a Consummating Order approving the project on or before this date. As of August 25, 2006, FPL and MoBay have been unable to agree on an extension of the contract. Under the current terms of the contract, MoBay will be able to terminate the contract at any time after September 29, 2006. FPL will also retain the right to terminate the contract for up to 90 days thereafter, or until December 28, 2006.

FPL does not intend to initiate termination of the contract if it receives final Commission approval prior to the end of the 90-day window, on December 28. If the Commission disapproved FPL's request for cost recovery or FPL did not receive approval by December 28, FPL would have to reevaluate whether to exercise its right to terminate the contract at that time.

MoBay is prepared to meet the target in-service date of April 2008, assuming FPSC approval by September 29, 2006. Any delay beyond September 29 will most likely result in a day-for-day delay of the in-service date.

If a final decision were reached by September 29, there would be no additional costs to FPL's customers. Because MoBay retains the right to terminate the contract after September 29, FPL is at risk for termination. In the event that MoBay gave notice of termination, FPL could attempt to renegotiate the contract to avoid termination but most likely this would have to be at the current market price for MoBay's storage capacity, which is above the pricing currently in FPL's contract.

Q. 12 For purposes of responding to this question, assume that there is a distinction between hedging for price volatility which protects the utility and its customers from an unstable market and hedging for supply reliability which protect the utility and its customers against disruptions of fuel supplies caused by strikes, acts of nature, etc. Please refer to Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket 011605-EI. Does this order authorize physical hedges for supply reliability? Please explain.

A. Order No. PSC-02-1484-FOF-EI does not distinguish between hedging for supply reliability versus hedging for price volatility; in fact, it would not be appropriate to distinguish between types of hedge. Hedging for supply reliability goes "hand in hand" with, and overlaps, hedging to reduce the risk of price volatility. Having access to a known quantity of supply at a known price during a supply disruption will provide greater cost stability. Natural gas storage will not only provide supply during times of disruption but also price protection from highly volatile natural gas prices and/or alternate fuels during each disruption event. Natural gas storage will allow FPL to continue running the most efficient generation on its system to meet demand, which, in turn, will reduce volatility. The Order also states that "the Proposed Resolution of Issues appears to remove disincentives that may currently exist for IOU's to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs." There is no distinction made in the Order between what types of hedging transactions qualify for recovery and, in fact, a note at the end of the hedging resolution approved by the Order specifically observes that "[n]o implication concerning the relative merits of using financial versus physical hedging should be drawn from this proposed resolution." FPL believes that natural gas storage is a prudent form of hedging that will provide benefits to its customers by providing supply security and volatility reduction and, therefore, should qualify for recovery through the fuel clause.

Q. 13 What is FPL's definition of physical hedging? Please provide examples.

A. Physical hedging involves the use of forward contracts to purchase the commodity itself, and/or the use of physical means of storing or producing the commodity to provide protection against future price swings. Examples of physical hedging include natural gas storage and fixed-price fuel purchases.

Q. 14 Please refer to pages 6 and 7 of FPL's petition and to page 3 of Gerry Yupp's affidavit. How is inventory carrying costs a hedging transaction cost? Please include any reference to orders, etc.

A. The utilization of natural gas storage is physical hedging. In fact, natural gas storage is commonly characterized within the industry as physical hedging. For example, the July 21, 2005 edition of Natural Gas Weekly Update published by the United States Department of Energy, observed in commenting on market trends that 47 of 54 American Gas Association (AGA) member companies surveyed reported using natural gas storage as a primary hedging tool and that "several companies noted that storage (as a physical hedge) is the only hedge they employ, choosing not to use financial instruments at all." In the case of storing gas as a physical hedge, the "hedging transaction" is the placement and retention of gas in storage for later use when needed. There are necessarily inventory carrying costs associated with retaining gas in storage, and those costs are therefore part of the hedging transaction costs.

Q.15 Does FPL believe that stored natural gas is fuel inventory? Please explain and include in the explanation comparisons/contrasts with heavy oil stored in tanks, on site or off site, and coal piles, on site or off site.

A. Stored natural gas should not be referred to as "fuel inventory" in the conventional sense, because in reality storing gas serves the purpose of hedging. It would be misleading to analogize a supply of stored natural gas to the inventories of fuel oil or coal that FPL maintains, because the reasons for storing each commodity are significantly different. Fuel oil and coal must generally be delivered in large quantities to each plant site and stored, on-site, in the ordinary course of business in order to operate a power plant. Storing each fuel and drawing from inventory is a necessity to maintain normal operations. In contrast, natural gas storage is not required for the ordinary operation of gas-fired plants. Natural gas is transferred directly from a pipeline into the power plant. Natural gas is scheduled, delivered and consumed from a pipeline on what can be termed a "real-time" basis. The intermediate step of storing a fuel is not a requirement for ordinary natural gas operations. Natural gas storage is generally utilized under "abnormal" conditions that are impacting the real-time delivery or price of natural gas

Q. 16 For each fossil fuel FPL burns, at what point in the transportation chain does it take ownership?

A. FPL takes ownership of heavy and light fuel oil when the commodity passes the flange going into the terminal or tank. FPL takes ownership of natural gas at the receipt point. FPL takes ownership of coal when the rail car is loaded (rail transportation) or when the ship is loaded (water transportation).

Q.17 For each fossil fuel, at what points the transportation chain is the fuel considered fuel inventory of FPL?

A. FPL accounts for heavy and light fuel oil as inventory when the commodity passes the flange going into the terminal or tank. As discussed in the response to Data Request No. 15, stored natural gas should not be referred to as "fuel inventory" in the conventional sense, because in reality storing gas serves the purpose of hedging. In ordinary operations where natural gas storage is utilized, there is no point in the transportation chain where natural gas is accounted for as inventory. When natural gas is stored as a physical hedge, FPL accounts for it when the commodity passes through the official receipt point going into the storage facility. FPL accounts for coal as inventory when the rail car is unloaded at the plant (rail transportation) or when the ship is unloaded at the dock (water transportation).

Q. 18 For off-site storage of fossil fuel (heavy oil and coal), identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale, please cite applicable rules or orders.

A. FPL does not have off-site storage for heavy oil and coal. For certain facilities, heavy oil is temporarily held at a terminal in order to facilitate the use of appropriate equipment for plant delivery, but FPL does not consider this to be storage (certainly not in the sense that natural gas is stored).

Q. 19 For on-site storage of fossil fuel (heavy oil and coal), identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale, please cite applicable rules or orders.

A. On-site storage costs for heavy oil and coal are included in base rates.

Q. 20 If storage costs are recovered through the fuel clause, for the delivered price of that fuel, detail whether you have considered storage costs to be commodity, transportation or hedging costs.

A. Natural gas storage costs are gas transportation charges and hedging transaction costs

Q. 21 If fuel carrying costs are applicable to any fuel storage, indicate whether those costs are recovered through the fuel clause or base rates. Is there a difference in treatment of carrying costs on fuel stored on-site vs. off-site? What is your rationale for any recovery of fuel inventory carrying cost through the fuel clause?

A. Fuel oil and coal inventory carrying costs are included in base rates. FPL does not store fuel oil or coal off-site. The Hedging Resolution approved by the Commission in Order No. PSC-02-1484-FOF-EI provides for recovery of physical and financial hedging transaction costs through the fuel cost recovery clause. Because natural gas inventory carrying costs are a result of executing a physical hedge transaction, this cost is recoverable through the fuel cost recovery clause consistent with that order.

Q. 22 How may barrels of heavy oil are in FPL's rate base?

A. The ending monthly balance of heavy oil included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Heavy Oil - Barrels in Rate Base
January	3,650,000
February	3,649,999
March	3,650,000
April	3,649,999
May	3,650,004
June	3,650,006
July	3,650,009
August	3,650,002
September	3,650,003
October	3,650,004
November	3,650,000
December	3,650,000

Q.23 How many MMBtu's of heavy oil are in FPL's rate base?

A. The ending monthly balance of heavy oil included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Heavy Oil - MMBTUs in Rate Base
January	23,360,000
February	23,359,994
March	23,360,000
April	23,359,994
May	23,360,026
June	23,360,038
July	23,360,058
August	23,360,013
September	23,360,019
October	23,360,026
November	23,360,000
December	23,360,000

Assumption: 6.4 mmbtus / barrel

Q. 24 How many tons of coal are in FPL's rate base?

A. The ending monthly balance of coal included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Coal - Tons in Rate Base
January	211,629
February	211,628
March	211,628
April	211,631
May	211,632
June	232,793
July	232,793
August	232,793
September	232,793
October	211,632
November	211,629
December	211,629

Q. 25 How many MMBtu's of coal are in FPL's rate base?

A. The ending monthly balance of coal included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Coal - MMBTUs in Rate Base
January	4,015,283
February	4,015,259
March	4,015,259
April	4,015,296
May	4,015,320
June	4,416,832
July	4,416,832
August	4,416,832
September	4,416,832
October	4,015,320
November	4,015,283
December	4,015,283

Assumption: SJRPP = 12,271 btu/lb
Assumption: Scherer = 8,730 btu/lb

Q. 26 How many barrels of light oil are in FPL's rate base?

A. The ending monthly balance of light oil included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Light Oil - Barrels in Rate Base
January	557,017
February	557,017
March	557,017
April	556,956
May	553,628
June	549,911
July	539,632
August	534,964
September	534,292
October	534,228
November	534,226
December	534,223

Q. 27 How many MMBtu's of light oil are in FPL's rate base?

A. The ending monthly balance of light oil included in rate base per FPL's 2006 MFRs in Docket No. 050045-EI is summarized as follows:

	Light Oil - MMBTUs in Rate Base
January	3,247,409
February	3,247,409
March	3,247,409
April	3,247,053
May	3,227,651
June	3,205,981
July	3,146,055
August	3,118,840
September	3,114,922
October	3,114,549
November	3,114,538
December	3,114,520

Assumption: 5.83 mmbtus / barrel

Q. 28 If FPL had 6,000,000 decatherms in storage in 2005 and used the supply in storage following Hurricane Katrina, how soon after using the supply in storage would it have replenished the supply? How would it have known that the timing was right?

A. Numerous factors must be considered in determining how quickly to replenish natural gas storage following an extreme weather event that results in natural gas supply disruptions. The potential for subsequent storms, the availability of natural gas, current fuel oil inventories, projected fuel oil deliveries and overall projected fuel requirements would all be considered in making this decision. In the case of Hurricane Katrina, FPL replenished its natural gas inventory as soon as possible as another storm had developed shortly after Katrina made landfall and there was a high level of uncertainty surrounding the extent of continued supply disruptions, as well as the impact another storm could have on fuel oil deliveries. There is no simple formula for determining the proper timing for replenishing natural gas storage; all potential scenarios must be evaluated at the time and taken into account in making this decision.

Q. 29 When FPL reports purchases of fuel on its monthly Schedule A-5, does it report any units that are not physically located at an FPL power plant or at Plant Scherer or St. Johns River Power Park? Please distinguish between fuel that is at a non-FPL-power-plant location and fuel that is in transit from a non-FPL-power-plant location.

A. Yes. FPL reports purchases/deliveries on the monthly Schedule A-5 once they have been physically brought into inventory as described in response to Data Request No. 17.

Q. 30 Do the quantities of oil and coal reported as purchases on Schedule A-5 differ from the quantities reported on the FPSC 423 Forms?

A. No, the quantities do not differ in total. There can be slight timing differences, where a purchase is reported in the following month (due to accounting treatment), but all purchases are reported on both the Schedule A-5 and FPSC 423.

Q. 31 If FPL receives heavy oil at the Sanford plant to be burned at Sanford Unit #3, through a terminal in Jacksonville, FL, does FPL report the oil in its inventory when it is on the way to the terminal, at the terminal, on the way from the terminal to Sanford, or only after the oil is received at the Sanford Plant?

A. FPL reports the oil in inventory when it is at the terminal and FPL takes ownership.

Q. 32 If FPL receives heavy oil at the Cape Canaveral plant to be burned at Cape Canaveral Units #1 or #2, through the Port Canaveral Terminal, does FPL report the oil in its inventory when it is on the way to the terminal, at the terminal, on the way from the terminal to the Cape Canaveral plant, or only after the oil is received at the Cape Canaveral Plant?

A. FPL reports the oil in inventory when it is at the terminal and FPL takes ownership.

Q. 33 Is the Boca Grande terminal in FPL's rate base?

A. The physical facilities are no longer in rate base because they have been demolished and retired. The land on which this facility was formerly located is included in rate base.

DOCKET NO. 060362-EI
STAFF'S FIRST DATA REQUEST

1. At the May 30 conference call staff raised a concern regarding processing plants. Some processing plants had operational problems during the 2005 Gulf of Mexico hurricanes which prevented or interrupted the flow of natural gas into the Gulfstream pipeline. Does the gas from MoBay storage enter a processing plant prior to entering the Gulfstream pipeline? If the answer is yes, could difficulty with the processing plants during or after a storm interfere with the use of MoBay storage as a supplier of gas to Gulfstream? Please address this concern and provide a map showing the location of Gulfstream's processing plant and compressor station in relation to MoBay's facilities and Gulfstream's termini.

Natural gas that is withdrawn from the MoBay storage facility will not enter a processing plant prior to entering the Gulfstream and/or FGT pipelines. FPL will inject pipeline quality gas into the MoBay storage facility and receive pipeline quality gas from the MoBay storage facility. The MoBay facility will have processing equipment on-site, mainly in the form of filter separation and water removal (dehydration) equipment. This on-site equipment will provide assurance that the natural gas withdrawn from the reservoir storage is of equal quality to the natural gas injected into the reservoir storage.

2. Regarding MoBay's storage as a temporary alternative to off-shore gas, please explain the series of steps that would occur in getting gas from MoBay to Gulfstream and FGT if Zone 3 gas becomes unavailable during a storm.

FPL would first communicate with its suppliers on the timing and level of natural gas curtailments. At that point, FPL would identify its requirements for withdrawals from storage, based on system load, alternate fuel inventories, alternate fuel availability and future weather projections. These withdrawal requirements would be evaluated against the current storage levels and withdrawal capabilities. Once the appropriate withdrawal level was determined, FPL would schedule this volume with Gulfstream and/or FGT as a withdrawal from MoBay at the receipt points into FPL's firm transportation contracts on each pipeline. This nomination would be done through each pipeline's scheduling system. FPL would then notify MoBay of the withdrawal volume from storage.

3. During the May 30 conference call FPL emphasized that its proposed participation in MoBay was primarily to physically hedge the supply of gas and thereby aid reliability during Gulf of Mexico storms. FPL also indicated they did not perform a formal cost/benefit study to support its proposed participation in MoBay. Given that reliability is FPL's primary reasons for its proposed participation in MoBay, please provide any reliability studies that FPL relied upon in reaching its decision to pursue participation in this storage project.

At the outset, it is important for Staff to recognize that FPL's primary reason for its proposed participation in MoBay is to hedge the physical supply of natural gas, which will result not only in an increase in reliability but also will reduce fuel price volatility and create a potential for fuel cost savings. The MoBay project was evaluated against four other storage alternatives and clearly represented the least-cost option for FPL's customers. The MoBay project also provides the highest level of operational flexibility. Currently, all natural gas supply into the Gulfstream pipeline is sourced from offshore production. The MoBay project will provide FPL with an alternate gas supply source into the Gulfstream pipeline when off-shore production is curtailed. MoBay will be the only storage facility directly connected to the Gulfstream pipeline.

FPL's evaluation of its fuel-supply reliability requirements led it to target having access to 900,000 mmBtu per day of natural gas supply during curtailment events. This volume will allow FPL to fuel its gas-only units without limitation and provide the flexibility to help manage fuel oil inventory if necessary. FPL assumed that approximately 225,000 mmBtu per day of natural gas would be available under most circumstances from on-shore supply in Zone 1 and Zone 2. Therefore, withdrawal requirements from natural gas storage of 675,000 mmBtu per day are necessary to reach the targeted 900,000 mmBtu per day supply level. FPL plans for this withdrawal capability to come from the expansion of Bay Gas to 2 Bcf (325,000 mmBtu per day withdrawal rights) coupled with the proposed MoBay project of 6 Bcf (350,000 mmBtu per day withdrawal rights).

In addition to helping meet FPL's targeted 900,000 mmBtu per day supply level, the MoBay project will enhance reliability by providing FPL with alternate supply sources for both the Gulfstream and FGT pipelines. Thus, not only will FPL have additional gas-supply capacity in the event of a disruption to off-shore supply sources, it will also have greater flexibility in how to transport stored gas to FPL's gas-fired power plants. This further enhances reliability by reducing the risk of gas-transportation disruptions.

Finally, as noted above, the MoBay project will hedge the physical supply of natural gas. As with all forms of hedging, the acquisition of natural gas storage will result in a reduction in fuel price volatility and may potentially result in fuel savings. While it is difficult to quantify to any degree of certainty a cost/benefit analysis of the MoBay project, there are clear indications that participation in natural gas storage can bring additional value to FPL's customers outside of just fuel supply reliability. As reported in FPL's annual hedging filing, natural gas storage has contributed approximately $12.5 million in fuel savings over the past two years. A significant portion of these savings (roughly $10.5 million) have been achieved during extreme weather events that result in natural gas curtailments. Natural gas storage has also been beneficial in helping FPL manage day-to-day and intra-day changes to natural gas requirements by helping to avoid higher-priced next day/intra-day natural gas or the consumption of alternate fuels. This form of natural gas storage utilization has delivered roughly $2 million in fuel savings over the two year period. During this same two year period, FPL incurred approximately $95 million of increased fuel costs due to natural gas curtailments. This expense represents the incremental replacement cost of re-supplying natural gas that had been curtailed. Natural gas storage can help limit this exposure to the cost of replacement fuel.

4. If FPL did not participate in the MoBay storage project but continued to pursue their current projects to enhance reliability, what is the probability of FPL not meeting its firm retail load commitments? Please provide any studies that support this response.

The probability of FPL not meeting its firm retail load commitments as a result of not participating in MoBay is extremely difficult to project. The specific details of severity, timing and location of extreme weather events will ultimately dictate their impact on the availability of fuel to meet firm load. There is simply not enough data available to evaluate all permutations of those specific details, which would be necessary in order to perform a fully quantitative probability assessment. However, Staff's question can be addressed qualitatively based on FPL's extensive experience in operating its generating system.

FPL's capability of fueling its generating fleet with heavy oil and distillate fuel oil is substantial enough to sustain operations through one, short-term severe weather event that impacts natural gas availability. However, while meeting load requirements after one such weather event is not a major reliability concern, back-to-back events would present a much more difficult challenge. In order to rely on power generated from burning heavy oil and distillate oil following a second short-term severe weather event, it would be imperative to have enough time between events to replenish the inventories of those fuels. This is not an easy task. Keep in mind that heavy oil and distillate oil are logistically more difficult to obtain than natural gas because they are not delivered real-time through a pipeline. Typically, the re-supply turnaround time for heavy oil is ten days. Distillate oil re-supply is a function of truck availability and supply availability. Typically, re-supplying one combustion turbine that has run for eight hours on distillate oil normally takes one to one-and-a-half days with normal truck and supply availability. During this re-supply period, FPL would experience a window of vulnerability to a second severe weather event. Moreover, the re-supply of heavy oil and distillate oil can be impacted by the same weather event that disrupted natural gas availability in the first place, so this window of vulnerability could be much longer than the timeframes described above.

An example from the 2004 hurricane season will help illustrate these fuel-supply challenges and how they interrelate. In 2004, weather events prohibited FPL from receiving fuel oil deliveries from BORCO, a Bahamian terminal where approximately 50% of FPL's heavy oil vessels load, for 30 days. This scenario forced FPL to increase its natural gas consumption to maintain inventories in preparation for potential future events. Additional natural gas storage would have been beneficial during this period, not only from a supply standpoint, but also in limiting FPL's exposure to the highly volatile natural gas market. More recently, during the 2005 hurricane season, the impact of storms on the Gulf of Mexico affected both natural gas and fuel oil production. Distillate supply was scarce throughout Florida; however, FPL's ability to manage its distillate inventory was limited as natural gas curtailments were severe. In each of the past two hurricane seasons, multiple severe weather events dictated that planning around all fuel types was imperative to meet current and potential future requirements.

Increasing the natural gas storage available to FPL will improve reliability by providing an alternate supply of natural gas that can be used not only to meet real-time fuel requirements, but also to manage fuel oil inventories to be better prepared to handle multiple events. There is no one specific project that will alleviate the need for all other types of mitigation strategies. FPL is aiming to have a diverse portfolio of strategies to help enhance fuel supply reliability and to help reduce volatility in its fuel costs.

5. At the May 30 conference call staff raised a concern regarding the ability of MoBay's above ground facilities to perform during a hurricane. How reliable will MoBay's facilities be if the Mobile area is hit by a hurricane? Please explain.

MoBay's facility specifications and operating procedures during hurricane conditions are provided below.

Facility Specifications

MoBay's North Dauphin Island (NDI) and Northwest Dauphin Island (NWDI) platforms will be modified and natural gas pipelines designed, constructed, and operated to comply with all applicable Department of Transportation (DOT), Minerals Management Service (MMS), Alabama Oil and Gas Board (AOGB) and Alabama Department of Conservation and Natural Resources regulations. The existing NDI and NWDI platforms, built for the Atlantic Richfield Company (ARCO), are designed to withstand Category 5 hurricane conditions. The proposed MoBay Pipeline will be designed for 1200 MAWP, using premium quality material per applicable API and DOT standards for hydrocarbon transmission pipelines. The pipeline is sized as a 36" diameter line of API 5L X65 grade carbon steel of 0.469" wall thickness (based on 0.72 design factor for class 1 location). The pipeline will be externally coated with 14 mils of fusion bond epoxy and also concrete weight coated (approx 3.75" thickness) to ensure buoyancy effect is removed for intended natural gas transmission service.

A Shutdown valve and pipeline pig launching facility will be provided on departing pipeline station at NDI platform. No additional valves are needed until landfall, where mainline isolation valves will be provided in the event isolation is needed. In addition, all offshore pipelines departing fixed structures (main line and distribution system) will be equipped with fail-safe automatic shutdown valve to assure system integrity exists should an emergency condition arise.

The installed wall thickness, and depth of cover would comply with the applicable requirements and would address any safety concerns specific to different sections of the pipeline route. Pursuant to DOT regulations, the natural gas pipelines will be installed at a minimum depth of 4 feet below the preexisting bottom elevation, a minimum of 10 feet in shipping fairways, and a minimum of 17 feet in anchorage area crossings where the depth of cover varies.

Reliability During Extreme Weather (Hurricanes)

The MoBay storage facility is designed maintain routine injection and withdrawal of natural gas during hurricane conditions. The facility's systems will be designed to operate unmanned for the typical forecast time span of a severe storm period duration. During hurricane conditions, the field operations crew will be moved to shore in a safe location, and the onshore facility will continue to operate as designed (also in hurricane readiness mode), for the predicted storm case. The main control system will be located within the onshore main station facilities office building. From this location, it will be possible to remotely control the wells regulating flow as needed for gas injection and/or withdrawal from the storage wells and distribution system. The conditions will be monitored and actions implemented by use of primary discrete data radio transmission system backed up by satellite transmission and a fiber optic cable network to the well sites and feedback to the master control onshore main station.

The offshore structures are designed to safely withstand predicted storm wave, current and wind conditions as established by API standards for the design of fixed structures in marine environment. Specifically, the structures will be designed for 29' ft storm wave with 14.9 sec wave period (33 ft max wave including tidal effect), and sustained winds of 170 mph with gusts of 200 mph. In the unlikely event damage occurs to the pipeline or distribution system, resulting in a significant leak and pressure loss, local safety shutdown systems will shutdown flow into/out of the affected operations lines to ensure safe operating conditions continue.

During storm conditions, operations will remain much the same as routine operations with exception of booster compression being shutdown on NDI, which is recommended when the operations crew evacuates due to the potential problems running offshore turbines unattended for extended period of days. Offshore booster compression facilities will not be necessary for routine withdrawals and will be shutdown during hurricane conditions. MoBay will continue to operate the onshore compression equipment during hurricane conditions as other major pipeline compressor station plants in the immediate area operate (for example, Gulfstream). During injection, gas will free-flow from onshore transmission interconnects directly into main 36" pipeline, then flowing through NDI/NWDI manifolds and on to the tripods wells into storage reservoirs.

Gas will be regulated into or out of the storage wells according to the otherwise normal injection/withdrawal operations cycles. During withdrawal cycle, gas will flow from the wells into distribution network onto NDI and NWDI collection manifolds, gas will then flow onto shore through the 36" main submarine pipeline to shore, and will be received at the onshore facility and undergo compression and dehydration. Gas leaving dehydration onshore will then flow to the transmission pipelines via the 24" trunklines connecting main station to transmission pipeline interconnection metering and regulating stations.

The overall facility will normally be powered by Alabama Power Co which can sufficiently meet MoBay electrical loads. However, in the event of power outage, the entire facility can continue to operate indefinitely as a self-contained operation having stand-by electrical power generator sufficient to handle the normal facility electrical loads. Other facilities such as water and sanitary facilities will also be provided on-site as self-contained units capable of operating for extended time frames as needed.

Plans are also being prepared to arrange for mutual assistance with Gulfstream Pipeline Co. (due to MoBay's close proximity to their station no. 410 who also has self-sufficient facilities), along with other industry in the general area to share auxiliary power or other service needs in worst case situations brought on by storm conditions or other undesirable events.

In advance of hurricane season itself, Hurricane Operations Plans and Procedures will be implemented, allowing for heightened awareness of Hurricane Mode storage facilities and system operations parameters, along with adaptation of actual hurricane operations procedures.

Of these, key steps will include platform and production systems checks following specified checklists (along with reporting functions), hurricane mode settings applied to telemetry, injection/withdrawal operations, and complete system operations checks to ensure communications and automation systems are fully functional in conjunction with primary storage facility operations.

In addition, thorough preparation of all equipment and operations facilities/gear will be made with all specialty and auxiliary items or material or product handling gear (slings, hoses, loose piping, bulk materials, etc), which will be: a) off-loaded and transferred to shore, b) stowed properly within storm-rated enclosures and c) other essential items exposed to weather will be tied-down properly to prevent release during storm condition causing unnecessary loss or damage. Hurricane evacuation plans and drills will also be implemented to ensure operations readiness and to allow timely safe departure of Field Operations staff.

<u>MoBay Hurricane Experience</u>

Experience has shown existing MoBay offshore platforms have withstood a series of major hurricanes passing in very close proximity to the actual MoBay facilities location since initial installation of 1990. The existing structures and facilities have sustained no damage to either structural integrity or operational functionality following more recent devastating tropical storms (including Hurricane Ivan in 2004 which passed directly over MoBay field operations and more recently Hurricane Katrina which passed only a few miles to the west).

These results demonstrate that the design criteria followed and construction methods applied for existing MoBay the fixed structures is adequate for proposed MoBay storage hub operations. Specifically, this refers to the existing NDI and NWDI platforms (refer to structural design criteria details below), which will function as manifold platforms for the gas proposed distribution system. In addition, this storm criteria and storm endurance requirement will similarly apply to the future braced-caisson tripod-well support structures, to be designed and installed according to the same storm wave and wind conditions to assure these future structures are capable of withstanding perceived worst case storm conditions over the predicted life of the project. This design basis is an essential element of the MoBay project to assure end-to-end system integrity for all predictable weather conditions so gas activities can continue uninterrupted during tropical storms, and better serve the end-users.

Results of recent storms in terms of operations impact on the existing gas production system, revealed that timely site safety preparations and field personnel evacuation from NDI living quarters (24 hr manned facility) was accomplished within safe allowable time frame in advance of the storms, followed by field operations crew return immediately after storm passage with prompt returned to normal production operations within 24 hours.

6. Please refer to paragraph 15 on page 7 of your petition in response to the following question. Please provide a schedule quantifying the carrying cost associated with the inventory at Bay Gas for 2006 projected.

Please see the attached schedule, which calculates the inventory carrying costs for the gas inventory at Bay Gas and MoBay. The inventory carrying cost is approximately $1 million for Bay Gas and approximately $5.9 million for MoBay, using comparable assumptions about the rate of return, the cost of the gas in inventory, and inventory levels as a percentage of total storage capacity. The pretax cost of capital used in the return on investment calculation is 11.7655% which is consistent with the cost of capital used in the cost recovery clause return on investment calculations. For Bay Gas, actual gas inventory balances are used for December 2005 through May 2006 and the balances for the remainder of the year use the May 2006 balance. For MoBay, Bay Gas inventory percentages are applied to MoBay storage capacity for illustrative purposes.

7. As an alternative to MoBay, did FPL consider expanding its storage participation with Bay Gas? Please explain if it was considered, why FPL chose not to pursue expansion and if it was not considered, why it wasn't considered.

FPL is expanding its storage participation with Bay Gas. Beginning in July 2007, FPL's participation in Bay Gas is increasing from 1 BCF to 2 BCF. FPL's firm daily withdrawal quantity will increase from 125,000 mmBtu per day to 325,000 mmBtu per day. FPL entered into this agreement in July 2005. The expansion in Bay Gas, in conjunction with the MoBay project provides diversity in FPL's physical supply hedge portfolio and the appropriate amount of daily withdrawal capability. A further expansion of Bay Gas was also considered as an alternative to the MoBay project. However, MoBay proved to be a better alternative than a further expansion of Bay Gas, both financially and operationally.

ESTIMATED CARRYING COST
ON GAS INVENTORY
2006
Staff First Data Request No. 6
Docket No 060362-EI

MONTH	BAY GAS INVENTORY(1)	AVERAGE BALANCE	RETURN ON INVESTMENT(2)
Dec-05	13,962,172		
Jan-06	11,566,247	12,764,210	125,148
Feb-06	6,031,630	8,798,939	86,270
Mar-06	8,445,514	7,238,572	70,971
Apr-06	7,676,181	8,060,848	79,033
May-06	7,947,985	7,812,083	76,594
Jun-06	7,947,985	7,947,985	77,927
Jul-06	7,947,985	7,947,985	77,927
Aug-06	7,947,985	7,947,985	77,927
Sep-06	7,947,985	7,947,985	77,927
Oct-06	7,947,985	7,947,985	77,927
Nov-06	7,947,985	7,947,985	77,927
Dec-06	7,947,985	7,947,985	77,927
2006 TOTAL RETURN			**983,503**

Note 1: Actual gas inventory balances from December 2005 through May 2006
Balances for the remainder of the year use the May 2006 balance

Note 2: The pretax cost of capital used in the return on investment calculation is 11.7655%
consistent with the cost of capital used in the cost recovery clauses return on investment calculations

MONTH	MOBAY INVENTORY(1)	AVERAGE BALANCE	RETURN ON INVESTMENT(2)
Dec-05	84,077,940		
Jan-06	69,412,200	76,745,070	752,453
Feb-06	36,183,888	52,798,044	517,663
Mar-06	50,681,514	43,432,701	425,840
Apr-06	46,046,496	48,364,005	474,189
May-06	47,708,490	46,877,493	459,614
Jun-06	47,708,490	47,708,490	467,762
Jul-06	47,708,490	47,708,490	467,762
Aug-06	47,708,490	47,708,490	467,762
Sep-06	47,708,490	47,708,490	467,762
Oct-06	47,708,490	47,708,490	467,762
Nov-06	47,708,490	47,708,490	467,762
Dec-06	47,708,490	47,708,490	467,762
2006 TOTAL RETURN			**5,904,092**

Note 1: Bay Gas inventory percentages applied to MoBay storage capacity for illustrative purposes

Note 2: The pretax cost of capital used in the return on investment calculation is 11.7655%
consistent with the cost of capital used in the cost recovery clauses return on investment calculations.

FLORIDA SUPPLY/DEMAND BALANCE: BALANCED CASE

"AVERAGE ANNUAL" BILLION CUBIC FEET PER DAY	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
FLORIDA DEMAND:	1.45	1.46	1.85	1.86	1.86	1.98	1.92	2.30	2.48	2.88	3.16	3.33	3.31	3.21	3.11	3.22
FLORIDA SUPPLY:																
SUPPLY EXCLUDING SESH PROJECT	3.04	2.95	2.80	2.71	2.55	2.40	2.25	2.32	2.26	2.16	2.06	2.10	2.44	2.43	2.50	2.54
SESH SUPPLY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.93	0.93	0.93	0.93	0.93	0.93	0.93
TOTAL SUPPLY	3.04	2.95	2.80	2.71	2.55	2.40	2.25	2.32	2.46	3.09	2.99	3.03	3.37	3.36	3.43	3.47
SUPPLY SURPLUS/(SHORTFALL) WITH SESH	1.59	1.49	0.95	0.85	0.69	0.42	0.34	0.02	(0.03)	0.21	(0.18)	(0.31)	0.05	0.15	0.32	0.25
SUUPLY SURPLUS/(SHORTFALL) WITHOUT SESH	1.59	1.49	0.95	0.85	0.69	0.42	0.34	0.02	(0.23)	(0.72)	(1.10)	(1.23)	(0.87)	(0.78)	(0.61)	(0.68)

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Florida Power Light Company
Docket # 060001-EI
Staff's Fifth Set of Interrogatories
Question No.55
Attachment I

Q.

In responding to this interrogatory, refer to the testimony of Gerard Yupp filed by FPL on September 1, 2006 in Docket No. 060001. Provide a detailed breakdown of the $96,464,000 fuel savings value contained on page 11, line 15 of Witness Yupp's September 1, 2006, direct testimony. In responding include the following:

A. Differential dollar value and energy generated for each capacity type (steam-coal,

steam-oil/gas, steam-combined cycle, combustion turbine, nuclear, cogen, purchased power, and any others)

B. Differential dollar value and energy generated for each individual generating unit

A.

Please see attached. FPL will provide a revised answer addressing the $73,832,000 fuel savings value contained in its October 24, 2006 supplemental filing.

Florida Power Light Company
Docket No. 060001-EI
Staff's Seventh Set of Interrogatories
Interrogatory No. 67

DIFFERENTIAL ENERGY AND DOLLAR VALUE BY CAPACITY TYPE
(DIFFERENTIAL IS WITHOUT TP5 MINUS WITH TP5)

Nuclear			
YEAR	UNIT	GWH	TOTAL COST(M$)
2007	TURKEY POINT 3	0.0	0.0
2007	TURKEY POINT 4	0.0	0.0
2007	ST LUCIE 1	0.0	0.0
2007	ST LUCIE 2	0.0	0.0
	TOTAL NUCLEAR	0.0	0.0
Steam			
2007	TURKEY POINT 1	210.6	20.4
2007	TURKEY POINT 2	222.5	21.4
2007	PT EVERGLADES 1	75.7	8.1
2007	PT EVERGLADES 2	49.6	5.2
2007	PT EVERGLADES 3	189.2	18.1
2007	PT EVERGLADES 4	250.9	23.7
2007	RIVIERA 3	97.0	9.7
2007	RIVIERA 4	128.5	12.7
2007	CAPE CANAVERAL 1	191.5	18.8
2007	CAPE CANAVERAL 2	180.4	17.7
2007	CUTLER 5	11.2	1.7
2007	CUTLER 6	20.1	2.5
2007	SANFORD 3	49.8	5.4
2007	MANATEE 1	332.8	31.0
2007	MANATEE 2	339.2	31.7
2007	MARTIN 1	347.4	32.5
2007	MARTIN 2	199.2	17.9
	TOTAL STEAM-OIL/GAS	2895.9	278.5
CC			
2007	TURKEY POINT 5	-5642.4	-365.5
2007	LAUDERDALE 4	185.4	10.8
2007	LAUDERDALE 5	165.7	10.4
2007	FORT MYERS 2	492.5	32.7
2007	SANFORD 4	148.3	9.6
2007	SANFORD 5	260.9	17.0
2007	PUTNAM 1	144.0	11.7
2007	PUTNAM 2	142.4	11.7
2007	MANATEE 3	159.6	7.7
2007	MARTIN 3	286.3	19.7
2007	MARTIN 4	303.7	20.6
2007	MARTIN 8	146.1	-2.3
	TOTAL STEAM-CC	-3207.6	-215.8
COAL			
2007	ST JOHNS 1O	0.0	0.0
2007	ST JOHNS 2O	0.0	0.0
2007	SCHERER 4	3.1	0.1
	TOTAL STEAM-COAL	3.1	0.1
GT			
2007	FORT MYERS 3A_B	82.0	8.8
2007	FORT MYERS 1-12	8.1	2.9
2007	LAUDERDALE 1-24	2.1	0.6
2007	EVERGLADES 1-12	0.1	0.1
	TOTAL COMBUSTION TURBINE	92.3	12.3

COGEN			
2007	CEDAR BAY	0.7	0.0
2007	INDIANTOWN	16.4	0.5
2007	COG OFFPK	0.0	0.0
2007	COG ONPK	0.0	0.0
2007	COGFIRM1	0.0	0.0
	TOTAL COGEN	17.1	0.5
PURCHASES			
2007	ST JOHNS 1P	0.0	0.0
2007	ST JOHNS 2P	0.0	0.0
2007	UPS_SOUTHERN	20.0	0.4
2007	SHADY CT	0.0	0.0
2007	OLEANDER CT	11.1	1.4
2007	WILLIAMS	67.3	5.5
2007	PROGRESS	24.6	2.6
2007	DESOTO_CT	5.2	0.6
2007	INDIAN RIVER1	10.4	1.5
2007	INDIAN RIVER2	25.2	3.7
2007	INDIAN RIVER3	35.4	5.2
	TOTAL PURCHASES	199.3	21.0
OTHER			
2007	SLPURCH	0.0	0.0
2007	SLSALE	0.0	0.0
2007	OS FLA	0.0	0.0
2007	OS NonFLA	0.0	0.0
2007	SALES	0.0	0.0
	TOTAL OTHER	0.0	0.0
	TOTAL	0.0	96.46

Florida Power Light Company
Docket No. 060001-EI
Staff's Seventh Set of Interrogatories
Interrogatory No. 67

DIFFERENTIAL ENERGY AND DOLLAR VALUE BY UNIT
(DIFFERENTIAL IS WITHOUT TP5 MINUS WITH TP5)

YEAR	UNIT	GWH	COST(M$)
2007	TURKEY POINT 1	210.64	20.39
2007	TURKEY POINT 2	222.53	21.38
2007	TURKEY POINT 3	0	0
2007	TURKEY POINT 4	0	0
2007	TURKEY POINT 5	-5642.44	-365.47
2007	LAUDERDALE 4	185.35	10.84
2007	LAUDERDALE 5	165.67	10.38
2007	PT EVERGLADES 1	75.72	8.09
2007	PT EVERGLADES 2	49.61	5.18
2007	PT EVERGLADES 3	189.19	18.14
2007	PT EVERGLADES 4	250.94	23.72
2007	RIVIERA 3	97.03	9.7
2007	RIVIERA 4	128.54	12.7
2007	ST LUCIE 1	0	0
2007	ST LUCIE 2	0	0
2007	CAPE CANAVERAL 1	191.5	18.75
2007	CAPE CANAVERAL 2	180.4	17.69
2007	CUTLER 5	11.21	1.71
2007	CUTLER 6	20.13	2.48
2007	FORT MYERS 2	492.51	32.7
2007	FORT MYERS 3A_B	82.03	8.79
2007	SANFORD 3	49.79	5.4
2007	SANFORD 4	148.29	9.61
2007	SANFORD 5	260.91	17.04
2007	PUTNAM 1	143.97	11.69
2007	PUTNAM 2	142.39	11.73
2007	MANATEE 1	332.81	30.98
2007	MANATEE 2	339.24	31.68
2007	MANATEE 3	159.62	7.67
2007	MARTIN 1	347.41	32.53
2007	MARTIN 2	199.17	17.93
2007	MARTIN 3	286.34	19.72
2007	MARTIN 4	303.68	20.57
2007	MARTIN 8	146.08	-2.29
2007	FORT MYERS 1-12	8.06	2.89
2007	LAUDERDALE 1-24	2.07	0.58
2007	EVERGLADES 1-12	0.12	0.05
2007	ST JOHNS 1O	0	0
2007	ST JOHNS 1P	0.02	0
2007	ST JOHNS 2O	0	0
2007	ST JOHNS 2P	0	0
2007	SCHERER 4	3.08	0.06
2007	UPS_SOUTHERN	20.02	0.38
2007	SHADY CT	0	0
2007	OLEANDER CT	11.14	1.44
2007	WILLIAMS	67.31	5.54
2007	PROGRESS	24.6	2.61
2007	DESOTO_CT	5.19	0.6
2007	CEDAR BAY	0.71	0.01
2007	INDIANTOWN	16.39	0.49
2007	COG OFFPK	0	0
2007	COG ONPK	0	0
2007	INDIAN RIVER1	10.44	1.48
2007	INDIAN RIVER2	25.15	3.67
2007	INDIAN RIVER3	35.44	5.23
	TOTAL	0	96.46

Q.

In responding to this interrogatory, refer to the testimony of Gerard Yupp filed by FPL on September 1, 2006 in Docket No. 060001. For each of the two cases run by FPL in its POWERSYM to determine the $96,464,000 fuel savings, provide the capacity factor for each individual generating unit for the May through December 2007 period.

A.

Please see attached. FPL will provide a revised answer addressing the $73,832,000 fuel savings value contained in its October 24, 2006 supplemental filing.

CASE: WITH TURKEY POINT 5 IN SERVICE IN MAY 2007

		MONTHS							
YEAR	Unit Name	5	6	7	8	9	10	11	12
2007	CAPE CANAVERAL 1	0	11	16	18	16	7	14	23
2007	CAPE CANAVERAL 2	4	15	20	21	18	14	15	23
2007	CEDAR BAY	79	95	95	95	95	95	48	95
2007	COG OFFPK	75	77	76	75	78	75	76	77
2007	COG ONPK	25	23	24	25	22	25	24	23
2007	CUTLER 5	0	0	0	0	2	0	0	1
2007	CUTLER 6	0	0	0	1	2	1	0	0
2007	DESOTO_CT	0	0	0	0	0	0	0	0
2007	EVERGLADES 1-12	0	0	0	0	0	0	0	0
2007	FORT MYERS 1-12	0	0	0	0	0	0	0	0
2007	FORT MYERS 2	88	90	92	92	92	70	49	41
2007	FORT MYERS 3A_B	1	4	5	7	4	1	1	4
2007	INDIAN RIVER1	0	0	0	0	1	0	0	1
2007	INDIAN RIVER2	0	0	0	0	1	0	0	1
2007	INDIAN RIVER3	0	0	0	0	1	0	0	1
2007	INDIANTOWN	88	94	95	95	95	49	95	95
2007	LAUDERDALE 1-24	0	0	0	0	0	0	0	0
2007	LAUDERDALE 4	78	81	85	86	88	49	42	49
2007	LAUDERDALE 5	81	86	90	91	92	27	44	51
2007	MANATEE 1	47	55	64	59	62	43	2	15
2007	MANATEE 2	40	48	55	49	56	57	9	10
2007	MANATEE 3	83	86	89	90	91	94	91	92
2007	MARTIN 1	51	61	68	65	67	73	11	22
2007	MARTIN 2	34	39	45	42	44	9	0	0
2007	MARTIN 3	20	32	43	36	36	44	49	54
2007	MARTIN 4	25	37	48	42	46	57	54	59
2007	MARTIN 8	85	88	91	91	92	95	90	90
2007	OLEANDER CT	0	0	0	0	0	0	0	1
2007	PROGRESS	1	0	0	1	3	1	1	2
2007	PT EVERGLADES 1	2	3	2	8	7	2	1	0
2007	PT EVERGLADES 2	3	5	7	9	4	0	0	5
2007	PT EVERGLADES 3	5	22	32	26	30	30	24	30
2007	PT EVERGLADES 4	11	26	33	27	32	33	22	31
2007	PUTNAM 1	17	28	36	31	33	34	34	49
2007	PUTNAM 2	18	12	37	31	32	37	36	47
2007	RIVIERA 3	1	8	10	61	11	6	13	13
2007	RIVIERA 4	50	8	63	14	13	5	12	17
2007	SANFORD 3	1	0	0	4	4	1	2	6
2007	SANFORD 4	87	89	91	91	92	92	82	75
2007	SANFORD 5	84	89	91	91	92	83	81	76
2007	SCHERER 4	97	98	98	98	98	98	98	98
2007	SHADY CT	0	0	0	0	0	0	0	0
2007	ST JOHNS 1O	98	98	98	98	98	98	98	98
2007	ST JOHNS 1P	98	98	98	98	98	98	98	98
2007	ST JOHNS 2O	98	98	98	98	98	98	98	98
2007	ST JOHNS 2P	98	98	98	98	98	98	98	98
2007	ST LUCIE 1	79	98	98	98	98	98	98	98
2007	ST LUCIE 2	98	98	98	98	98	0	0	22
2007	TURKEY POINT 1	5	16	22	22	22	24	18	26
2007	TURKEY POINT 2	7	21	27	23	26	23	23	32
2007	TURKEY POINT 3	98	98	98	98	0	98	98	98
2007	TURKEY POINT 4	98	98	98	98	98	98	98	98
2007	TURKEY POINT 5	84	87	89	89	90	93	88	88
2007	UPS_SOUTHERN	97	100	100	100	100	100	100	100
2007	WILLIAMS	8	17	20	19	21	23	19	5

CASE: WITHOUT TURKEY POINT 5 IN SERVICE IN 2007

		MONTHS							
YEAR	Unit Name	5	6	7	8	9	10	11	12
2007	CAPE CANAVERAL 1	0	21	26	23	26	23	23	31
2007	CAPE CANAVERAL 2	9	22	32	26	29	26	21	29
2007	CEDAR BAY	80	95	95	95	95	95	48	95
2007	COG OFFPK	75	77	76	75	78	75	76	77
2007	COG ONPK	25	23	24	25	22	25	24	23
2007	CUTLER 5	1	4	4	7	6	1	0	3
2007	CUTLER 6	2	5	5	8	6	2	0	0
2007	DESOTO_CT	2	0	0	0	0	0	0	0
2007	EVERGLADES 1-12	0	0	0	0	0	0	0	0
2007	FORT MYERS 1-12	0	0	0	0	1	0	0	1
2007	FORT MYERS 2	91	92	93	94	94	79	65	53
2007	FORT MYERS 3A_B	3	9	12	14	9	4	2	6
2007	INDIAN RIVER1	1	2	2	5	5	1	0	4
2007	INDIAN RIVER2	1	2	3	5	5	2	1	3
2007	INDIAN RIVER3	1	1	2	3	5	1	1	4
2007	INDIANTOWN	93	95	95	95	95	49	95	95
2007	LAUDERDALE 1-24	0	0	0	0	0	0	0	0
2007	LAUDERDALE 4	83	87	91	92	93	59	54	57
2007	LAUDERDALE 5	87	92	94	94	95	35	57	61
2007	MANATEE 1	57	65	71	69	72	45	2	23
2007	MANATEE 2	51	56	63	60	64	60	11	17
2007	MANATEE 3	87	90	93	94	95	94	91	92
2007	MARTIN 1	62	69	74	72	74	76	19	28
2007	MARTIN 2	42	46	50	49	52	9	0	0
2007	MARTIN 3	30	42	52	46	48	55	61	66
2007	MARTIN 4	33	48	56	50	56	73	70	73
2007	MARTIN 8	89	92	94	95	95	95	89	91
2007	OLEANDER CT	0	1	1	3	2	1	0	3
2007	PROGRESS	2	5	5	9	8	3	1	6
2007	PT EVERGLADES 1	4	10	15	16	15	8	8	0
2007	PT EVERGLADES 2	4	11	18	19	4	0	1	9
2007	PT EVERGLADES 3	15	32	44	33	35	41	29	38
2007	PT EVERGLADES 4	22	37	45	40	41	50	34	37
2007	PUTNAM 1	23	38	47	42	44	52	46	51
2007	PUTNAM 2	24	14	49	43	45	55	47	53
2007	RIVIERA 3	3	9	22	66	19	15	14	22
2007	RIVIERA 4	58	15	69	21	21	15	17	29
2007	SANFORD 3	3	7	10	13	12	5	8	11
2007	SANFORD 4	90	91	93	94	94	93	86	78
2007	SANFORD 5	86	91	93	93	94	91	87	87
2007	SCHERER 4	98	98	98	98	98	98	98	98
2007	SHADY CT	0	0	0	0	0	0	0	0
2007	ST JOHNS 1O	98	98	98	98	98	98	98	98
2007	ST JOHNS 1P	98	98	98	98	98	98	98	98
2007	ST JOHNS 2O	98	98	98	98	98	98	98	98
2007	ST JOHNS 2P	98	98	98	98	98	98	98	98
2007	ST LUCIE 1	79	98	98	98	98	98	98	98
2007	ST LUCIE 2	98	98	98	98	98	0	0	22
2007	TURKEY POINT 1	12	28	35	29	33	35	24	33
2007	TURKEY POINT 2	17	29	36	33	35	40	34	36
2007	TURKEY POINT 3	98	98	98	98	0	98	98	98
2007	TURKEY POINT 4	98	98	98	98	98	98	98	98
2007	TURKEY POINT 5	0	0	0	0	0	0	0	0
2007	UPS_SOUTHERN	99	100	100	100	100	100	100	100
2007	WILLIAMS	15	27	34	32	33	40	30	8

Q.

In responding to this interrogatory, refer to the testimony of Gerard Yupp filed by FPL on September 1, 2006 in Docket No. 060001. Please refer to page 15, line 11 of the testimony of Gerard Yupp. What was the natural gas price that was used in the calculation of the $96,464,000 fuel savings? What index did FPL use to set that price? Why is that price reasonable as opposed to any other price index available to FPL?

A.

For reference, please refer to page 3, lines 8 through 23 and page 4, line1 of the testimony of Gerard Yupp filed by FPL on September 1, 2006 in Docket No 060001-EI. FPL used the NYMEX natural gas futures contract (forward curve) available on August 7, 2006 for the calculation of the estimated fuel savings associated with the addition of Turkey Point Unit 5. This forward curve for natural gas was used as input to the POWRSYM model to project total natural gas costs for the 2007 projected period. The August 7, 2006 NYMEX curve reflected an average commodity price of $9.40 per MMBTU. As described in Gerard Yupp's testimony, the basic assumption made with respect to using the forward curve is that all available information that could impact the price of natural gas in the future is reflected in the price curve at all times. The forward curve for natural gas represents expected future prices at a given point in time and is consistent with the prices at which FPL can transact its hedging program. Therefore, FPL considers the NYMEX forward curve price reasonable for its fuel cost calculations.

FPL will provide a revised answer addressing the $73,832,000 fuel savings value contained in its October 24, 2006 supplemental filing.

14. Please list all natural gas storage facilities where GULF has firm capacity commitments and for each facility state the amount of GULF's firm capacity commitment.

ANSWER:

Bay Gas Storage Company, Ltd.
Mobile, AL
Gulf Power firm capacity = 830,120 MMbtu

15. When did GULF begin using natural gas storage on a firm basis?

ANSWER:

Gulf Power began using gas storage on a firm basis on September 1, 1997 for Plant Crist.

16. Please state all fees and charges that GULF pays for natural gas storage.

ANSWER:

Gulf pays the following types of charges for natural gas storage: a Firm Storage Monthly Demand Charge calculated per MMBtu in storage; an Injection Charge calculated per MMBtu of gas received for injection; a Withdrawal Charge calculated per MMBtu of gas withdrawn; and a Fuel Charge calculated on a percentage of all volumes of gas received for injection.

17. For each fee or charge listed above, does GULF recover that fee or charge: in the fuel clause; as a part of base rates; or by some other recovery mechanism. For each item listed as being recovered through the fuel clause, please include GULF's rationale or justification for including the charge in the fuel adjustment clause.

ANSWER:

Fees and charges that Gulf pays to a third party for natural gas storage are recovered through Gulf's Fuel Cost Recovery Clause. These charges are appropriate for recovery through the fuel clause since they are subject to changes due to fluctuations in volume and the number of withdrawals and injections of gas. Per FPSC Order #14546, dated July 8, 1985, in Docket No. 850001-EI-B, "Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause."

18. Are there any charges for natural gas storage that GULF does not charge to the fuel adjustment clause?

ANSWER:

Carrying costs of natural gas inventory are not charged to Gulf's Fuel Cost Recovery Clause, but are considered to be recovered through base rates.

19. For each fee or charge that GULF pays for natural gas storage service and that is recovered through the fuel clause, how is the fee or charge reported in the A schedules?

ANSWER:

Firm storage monthly demand charges, injection charges, withdrawal charges, and fuel charges, as described in the answer to question #16, are included as part of the unit cost of gas purchased on schedule A-5; and, therefore, are part of the total cost of gas burned shown on schedule A-5. This expense of gas burned, including any fees or charges for natural gas storage, is also reflected on schedules A-3 and A-4.

20. For each charge that a storage facility charges to GULF for storage services, how was the charge reported in the projected testimony used to set the fuel factor in 2005 and 2006?

ANSWER:

For the 2005 and 2006 projection filings, all natural gas storage fees and charges and any storage costs for off-site coal storage were included as part of the projected unit cost data on schedule E-5; and, therefore, were part of the total projected cost of fuel burned shown on schedule E-5. The projected expense of fuel burned, including any storage facility charges, was also reflected on schedules E-1, E-2, E-3 and E-4.

21. Does GULF pay for base gas at any of its gas storage facilities? Please explain.

ANSWER:

No. Base gas for the storage cavern is the responsibility of Bay Gas Storage Company, Ltd.

22. Does GULF provide its own base gas for any storage facility it uses?

ANSWER:

No. All gas injected into storage for Gulf Power is available to be withdrawn for Gulf Power's use at any time and is not characterized as base gas.

23. For each fossil fuel GULF burns, at what point in the transportation chain does it take ownership?

ANSWER:

The point at which Gulf takes ownership varies by individual contract. For example, Gulf takes ownership of natural gas when the gas is delivered to the plant for burn or when the gas is delivered to the storage facility for injection. Gulf takes ownership of oil when the truck is unloaded into the plant's storage tanks. For some coal, Gulf takes ownership when the coal is unloaded at its ultimate destination. In some cases, Gulf takes ownership when the coal is loaded into the transportation equipment (train, ship, or barge). Gulf also takes ownership of some coal when it arrives at intermediate transloading facilities.

24. For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of GULF?

ANSWER:

For accounting purposes, Gulf considers in-transit fuel to be part of inventory when the risk of loss is transferred to Gulf.

25. For each fossil fuel, if fuel storage is utilized, indicate whether there is fuel stored both on-site and off-site.

ANSWER:

Coal is stored both on the plant site and off site at various transfer points such as the McDuffie Coal Terminal at the Alabama State Docks.
Gas is stored off site at Bay Gas Storage.
Oil is stored only on the plant site.

26. For off-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

ANSWER:

Natural gas storage costs, including firm storage monthly demand charges, injection charges, withdrawal charges, and fuel charges; and any off-site coal storage charges related to the amount of tonnage and time period stored per contracted terms, are recovered through Gulf's Fuel Cost Recovery Clause. These charges are volatile and subject to changes due to fluctuations in volume and, therefore, are appropriate for recovery through the fuel clause as opposed to base rates, which is more appropriate for costs that are relatively fixed. Per FPSC Order #14546, dated July 8, 1985, in Docket No. 850001-EI-B, "Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause."

Carrying costs of inventory off-site are not charged to Gulf's Fuel Cost Recovery Clause, but are considered to be recovered through base rates.

27. For on-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of these costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

ANSWER:

All on-site storage costs, including carrying costs of inventory, are considered to be recovered through base rates and, therefore, are not charged to Gulf's Fuel Cost Recovery Clause.

28. If fuel carrying costs are applicable to any fuel kept in storage, indicate whether these costs are recovered through the fuel clause or base rates. Is there a difference in treatment of carrying costs on fuel stored on-site vs. off-site? What is your rationale for any recovery of fuel inventory carrying cost through the fuel clause?

ANSWER:

Carrying costs of fuel inventory are considered to be recovered through base rates. There is no difference in the treatment of carrying costs on fuel stored on-site vs. off-site.

29. What is GULF's definition of physical hedging? Please provide examples.

ANSWER:

Physical hedging involves executing various transactions that would include the procurement of or storage of fuel as a means of dampening upside fuel price risk.

An example of physical gas hedging using a procurement agreement would be contracting for firm gas supply at a fixed price delivered in defined volume increments per period of time over a defined term.

An example of physical gas hedging using storage would be purchasing a volume of gas at market price and injecting this gas into storage for the purpose of withdrawing this quantity of gas during times of higher market prices.

25. Please explain TECO's plans for using firm natural gas storage. Include the following in the explanation:
(A) when TECO plans to begin using natural gas storage;
(B) the planned amount of firm storage capacity;
(C) how TECO will recover the costs of natural gas storage; and
(D) how TECO will report the costs of natural gas storage.

A. Tampa Electric requests that its revised response to Staff's First Set of Informal Data Request No. 1, as filed on October 6, 2006, be adopted as the official response to this interrogatory.

26. For each fossil fuel TECO burns, at what point in the transportation chain does it take ownership?

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 2, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

27. For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of TECO?

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 3, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

28. For each fossil fuel, if fuel storage is utilized, indicate whether there is fuel stored both on-site and off-site.

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 4, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

29. For off-site storage of coal and heavy oil, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 5, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

30. For on-site storage of coal and heavy oil, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of these costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 6, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

31. If storage costs are recovered through the fuel clause for the delivered price of that fuel, detail whether you have considered storage costs to be commodity, transportation or hedging costs.

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 7, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

32. If fuel carrying costs are applicable to any fuel storage, indicate whether these costs are recovered through the fuel clause or base rates. Is there a difference in treatment of on-site vs. off-site storage? What is your rationale for recovery of fuel inventory carrying cost through the fuel clause?

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 8, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

33. What is Tampa Electric's definition of physical hedging? Please provide examples.

A. Tampa Electric requests that its response to Staff's First Set of Informal Data Request No. 9, as filed on August 25, 2006, be adopted as the official response to this interrogatory.

1. Please explain Tampa Electric's plans for using firm natural gas storage. Include the following in the explanation:
- when Tampa Electric plans to begin using natural gas storage;
- the planned amount of firm storage capacity;
- how Tampa Electric will recover the costs of natural gas storage; and
- how Tampa Electric will report the costs of natural gas storage.

A. Tampa Electric has used natural gas storage since Hurricane Ivan disrupted natural gas supplies in Mobile Bay and the eastern Gulf of Mexico in 2004. Tampa Electric replaced much of its lost gas supply with gas bought from gas marketers who had gas in storage.

Tampa Electric expanded its use of storage in 2005 to mitigate the risk of disruptions to natural gas supply. Tampa Electric contracted with gas marketers for call options on gas from storage during the 2005 hurricane season as well as for natural gas storage capacity. Effective July 14, 2005, Tampa Electric entered into a contract with Bay Gas Storage Company, Ltd. The contract provides Tampa Electric with 175,000 MMBtu of storage volume with a daily firm withdrawal capability of 35,000 MMBtu. On October 14, 2005, Tampa Electric entered a second agreement with Bay Gas Storage, which superseded the prior agreement. The new agreement extended the 175,000 MMBtu of previously contracted storage capacity until a new storage cavern is operational at Bay Gas. On August 29, 2006, Tampa Electric amended the previous agreement to increase the storage capacity to 225,000 MMBtu until the cavern is operational. At that time, the contracted capacity increases to 750,000 MMBtu and the withdrawal capability increases to 75,000 MMBtu per day. The agreement has a ten-year term and the new storage capacity is expected to be available beginning around April 1, 2007.

Costs for storage include a Firm Services Demand Charge based on the amount of storage space reserved, a variable Injection and Withdrawal Charge based on the movement of gas into and out of storage, and a Fuel Charge which is a percentage of gas retained by the storage operator to cover the fuel used in injection. These costs are recovered through fuel costs since they directly relate to the reliable, cost-effective acquisition of natural gas supply. The total costs are reported in the natural gas costs of actual fuel costs along with the cost of the commodity injected into the storage facility. The balance of gas in storage is valued at the end of each month and the monthly net change is expensed in that month.

2. For each fossil fuel TECO burns, at what point in the transportation chain does it take ownership?

A.

Commodity (Fossil Fuel)		Ownership Timing
Coal	▪ River transportation	▪ Once loaded into the barge
	▪ Ocean transportation (from origination)	▪ At delivery location (Terminal or Big Bend)
Natural Gas	▪ Receipt Area	▪ Into the pipeline
	▪ Market Area (Gas bought at the outlet of the interstate pipeline)	▪ At the plant
No. 2 Oil	▪ Truck Delivery	▪ At discharge into the tank at plant
	▪ Waterborne Delivery	▪ At discharge into the tank at plant
No. 6 Oil	▪ Truck Delivery	▪ At discharge into the tank at plant
	▪ Waterborne Delivery	▪ At discharge into the tank at plant
Propane	▪ Truck Delivery	▪ At discharge into the tank at plant

3. For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of TECO?

A. See Tampa Electric's response to Staff's First Set of Data Requests No. 2.

4. For each fossil fuel, if fuel storage is utilized, indicate whether there is fuel stored both on-site and off-site.

A.

Commodity Storage		
	On-site	**Off-site**
Coal	Yes	Yes
Natural Gas	No	Yes
No. 2 Oil	Yes	No
No. 6 Oil	Yes	No
Propane	Yes	No

5. For off-site storage of coal and heavy oil, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

A. Coal is stored off-site in Davant, Louisiana. A handling fee is charged for unloading and loading, sampling, storing, blending, pile maintenance, and dust suppressant. The terminal handling fee, which is part of the waterborne transportation rate for coal delivered from Davant, Louisiana to Tampa Electric power plants is recovered through the fuel clause. Tampa Electric does not have any off-site storage of heavy oil; therefore, there are no associated storage costs.

6. For on-site storage of coal and heavy oil, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of these costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

A. Tampa Electric incurs material and handling costs associated with storing and maintaining its coal and heavy oil inventory at the stations. All material and handling costs are treated as non-recoverable fuel and included in base rates, as required by Order No 14546, in Docket No. 850001-EI-B. The Commission also determined that coal inventory in working capital for Tampa Electric should be 98 days in Order No. PSC-93-0165-FOF-EI. Similarly, heavy oil inventory levels of 7 days were determined to be appropriate for inclusion in working capital in the same order. Therefore, any associated carrying costs for maintaining the necessary coal and heavy oil inventory is recovered through base rates. Currently, Tampa Electric treats any heavy oil storage costs as a base rate type expense.

7. If storage costs are recovered through the fuel clause for the delivered price of that fuel, detail whether you have considered storage costs to be commodity, transportation or hedging costs.

A. Natural gas storage costs are treated as a commodity cost, although there is an element of commodity, transportation and hedging in natural gas storage. Having a storage facility allows the utility to inject the purchased natural gas commodity over a time period and then retrieve it when needed. This reduces the daily purchases of natural gas, particularly intra-day, which are frequently more expensive and less firm.

Storage of natural gas is a physical and financial hedge. As described above, storage allows the utility to mitigate some risk that gas may not be available on the market when the utility has an emergency need. As a financial hedge it allows the utility to purchase lower priced base load or summer gas and utilize storage to mitigate the higher cost of swing gas or to sell higher priced winter gas.

Storage also potentially relieves some pipeline capacity transportation costs. Storage helps protect utilities from interstate pipeline alert day charges. A utility can avoid “underage”, too much gas into the pipe, alert day penalties by putting gas into storage while avoiding “overage”, not enough gas into the pipe, alert day penalties by pulling gas from storage. Thus, storage helps lower overall pipeline transportation costs.

For coal, off-site storage costs are recovered through transportation rates, which are recovered through the fuel clause.

8. If fuel carrying costs are applicable to any fuel storage, indicate whether these costs are recovered through the fuel clause or base rates. Is there a difference in treatment of on-site vs. off-site storage? What is your rationale for recovery of fuel inventory carrying cost through the fuel clause?

A. Though Tampa Electric does not recover any fuel carrying costs through the fuel clause at this time, if a fuel supplier charged a carrying cost for feedstock e.g. natural gas that was not included in base rates, the cost should be eligible for recovery through the fuel clause because it is a direct expense associated with providing a reliable and cost-effective fuel supply.

In the event a particular commodity, such as Tampa Electric's coal inventory, is included in base rates then recovery through the fuel clause would not be appropriate.

Currently, Tampa Electric incurs costs in financing charges and facilities costs to maintain the inventory. Buying fuel during a low demand season and storing it until it is needed provides the opportunity for both lower cost and greater reliability. This added flexibility should be a component of any fuel supply strategy. The benefit is passed directly to customers through the fuel clause.

9. What is Tampa Electric's definition of physical hedging? Please provide examples.

A. Tampa Electric's definition of physical hedging is mitigating the risk of insufficient fuel supply and the associated cost exposure created by insufficient physical commodity supply. Examples of physical hedging include storage of fuel commodity, natural gas pipeline park-and-loan agreements, diversity of power generation fuels, dual fuel at a power plant, access to multiple pipelines for natural gas supply and delivery, acquiring a call option for peaking power when a power plant is experiencing degraded performance and may fail at any time, and having an appropriate blend of long term coal supply contracts with minimum takes, intermediate term contracts and spot purchase opportunities. As seen by these examples, a "physical" hedge has an actual commodity/energy availability component compared to a "financial" hedge which only addresses price.

22. What is PEF's definition of physical hedging? Please provide examples.

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

23. For each fossil fuel PEF burns, at what point in the transportation chain does it take ownership?

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

24. For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of PEF?

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

25. For each fossil fuel, if fuel storage is utilized, indicate whether there is fuel stored both on-site and off-site.

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

26. For off-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

27. For on-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of these costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

28. If fuel carrying costs are applicable to any fuel storage, indicate whether these costs are recovered through the fuel clause or base rates. Is there a difference in treatment of on-site vs. off-site storage? What is your rationale for recovery of fuel inventory carrying cost through the fuel clause?

Answer: Please see PEF's response to Staff's Data Request in Docket No. 060001-EI dated August 25, 2006 attached hereto as Attachment A.

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

Before me, the undersigned authority, personally appeared JOSEPH F. McCALLISTER, who

(✓) is personally known to me, or

( ) produced ______________________ as identification and who, being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 21 through 28 of Staff's Sixth Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 060001-EI are true and correct to the best of his knowledge, information and belief.

Joseph F. McCallister

Director Gas and Oil
Title

Notary Public
State of North Carolina

My commission Expires: 12/16/2006

"OFFICIAL SEAL"
Notary Public, North Carolina
County of Johnston
Mary D. Fotch
My Commission Expires 12/16/2006

AFFIDAVIT

STATE OF NORTH CAROLINA)
)
COUNTY OF WAKE)

Before me, the undersigned authority, personally appeared ALEXANDER WEINTRAUB, who

(✓) is personally known to me, or

( ) produced ________________________________ as identification and who,

being duly sworn, deposes and says that the foregoing answers to Interrogatory Nos. 23 through 28 of Staff's Sixth Set of Interrogatories to Progress Energy Florida, Inc., in Docket No. 060001-EI are true and correct to the best of his knowledge, information and belief.

Alexander Weintraub

Title

Notary Public
State of North Carolina

My commission Expires: 12/16/2006

Progress Energy

Writer's Direct Dial No. (727) 820-5184

August 25, 2006

Ms. Lisa Bennett, Esquire
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Staff Data Request; Docket No. 060001-EI

Dear Lisa:

Please find attached Progress Energy Florida, Inc.'s responses to Staff's data request dated August 18, 2006. Please feel free to contact me should you have any questions.

Sincerely,

John T. Burnett LMS

John T. Burnett

JTB/lms

Cc: Parties of Record
Division of Commission Clerk (Docket File)
Division of Economic Regulation (Lester)
Division of Regulatory Compliance and Consumer Assistance (Vandiver)
Jack Shreve – Attorney General's Office
Charles Beck – Office of Public Counsel

Progress Energy Florida, Inc.
106 E. College Avenue
Suite 800
Tallahassee, FL 32301

1. **Please explain PEF's plans for using firm natural gas storage. Include the following in the explanation:**

   - when PEF plans to begin using natural gas storage
   - the planned amount of firm storage capacity
   - how PEF will recover the costs of natural gas storage
   - how PEF will report the costs of natural gas storage

   Answer:

   Please see PEF's responses to Questions 2, 3 and 4 to Staff's informal questions submitted on July 26, 2006 and discussed at the July 27, 2006 Fuel Status Meeting.

   PEF has executed two high deliverability storage service agreements beginning in May 2008 with a term of 5 years. During the months of June through October, the agreements have combined firm storage capacity of 1,250,000 MMBtu's with firm daily withdrawal capacity of 125,000 MMBtu's. For November through May the agreements have combined firm storage capacity of 1,000,000 MMBtu's with firm daily withdrawal capacity of 100,000 MMBtu's. This storage was purchased to provide greater gas supply reliability for short-term curtailments that could occur because of hurricanes or other weather related events. It is expected that natural gas storage demand costs, storage injection and withdrawal costs, and related gas purchases for storage will be recovered through the fuel and purchased power cost recovery clause in the same manner as gas supply and transportation costs are currently recovered on an as burned basis. Natural gas storage injections will be reported as increases to natural gas inventory. Storage demand costs, injection and withdrawal costs, and associated withdrawals of gas from inventory will be expensed on an as burned basis.

2. **What is PEF's definition of physical hedging? Please provide examples.**

   Answer:

   Physical hedging can be defined as the procurement of a fixed volume of natural gas for expected generation needs from a supplier at a fixed price per MMbtu. An example of a physical hedge executed by PEF was the procurement of physical natural gas from a supplier for the months of May through October 2006 delivered to Destin into Gulfstream at a fixed price per MMbtu. PEF's objectives of executing physical hedges are to provide physical supply, mitigate price risk and volatility, provide greater price certainty and smooth out prices over time, and maintain a diverse portfolio of volumes and prices over time.

3. **For each fossil fuel PEF burns, at what point in the transportation chain does it take ownership?**

   Answer:

   - Coal – PEF takes ownership when the coal is loaded on a train or barge.
   - Heavy Oil – PEF takes ownership when heavy oil is delivered to the plants.

- Light Oil – Most of PEF's suppliers deliver light oil by truck directly to the plants where PEF takes ownership. One of PEF's suppliers ships light oil by barge. PEF takes ownership of this product when it is loaded on the barge.
- Natural Gas – PEF takes ownership of natural gas at PEF's contractual receipt points which include pipeline interconnects, pipeline pooling points, and various other delivery points along the transportation chain. When the natural gas storage service agreements described in No. 1 above become effective beginning May 2008, PEF will own the gas that is held in the respective third party storage facility..

4. **For each fossil fuel, at what points in the transportation chain is the fuel considered fuel inventory of PEF?**

Answer:

Fuel is considered fuel inventory when PEF takes ownership.

5. **For each fossil fuel, if fuel storage is utilized, indicate whether there is fuel stored both on-site and off-site.**

Answer:

- Coal – Fuel is stored both on-site and off-site.
- Heavy Oil – Fuel is stored on-site only.
- Light Oil – Fuel is stored both on-site and off-site
- Natural Gas – PEF does not currently store natural gas. However, as described in No. 1 and 3 above, natural gas will be stored off-site beginning in May 2008.

6. **For off-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of those costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.**

Answer:

All costs associated with off-site storage are recovered through the fuel clause. The following are specific costs recovered through the fuel clause for each applicable fuel type.

- Coal – Fuel is stored off-site at two locations at the mouth of the Mississippi River. PEF does not pay a fee for the storage itself. Rather, PEF pays a transloading fee per ton when the coal is unloaded from river or ocean vessels into stockpiles or gulf barges.

- Light Oil – Currently PEF stores light oil at a terminal owned by Martin Gas Terminals in Tampa, FL. Costs associated with this storage facility include fees for tank capacity as well as a cost/gallon to input or withdraw the oil.

- Natural Gas – Although PEF does not currently have off-site storage for natural gas, beginning in May 2008, PEF expects to recover the demand costs as well as storage injection and withdrawal costs through the fuel clause.

Rationale: PEF currently recovers, or expects to recover in the case of natural gas, these off-site storage costs through the fuel clause. These storage costs are associated with transporting fuel to PEF's terminals that are dedicated to the supply of its generating plants. Furthermore, the cost of storage fluctuates with the volume of fuel stored. FPSC Order No. 14546, July 8, 1985, states the following:

> Transportation Charges. The costs associated with moving fuel to fuel storage locations and terminals dedicated to the supply of a utility's generating facility are subject to significant changes due to fluctuations in distances, deliveries, volume and price. Consequently, such costs should be recovered through fuel adjustment clauses.

7. **For on-site storage, identify which costs of storage are recovered through the fuel clause and which costs are recovered through base rates. For any fee or charge recovered through the fuel clause, state the utility's rationale for recovery of these costs through the fuel clause as opposed to base rates. When providing the rationale please cite applicable rules or orders.**

<u>Answer</u>:

All costs of on-site storage are recovered through base rates.

8. **If fuel carrying costs are applicable to any fuel storage, indicate whether these costs are recovered through the fuel clause or base rates. Is there a difference in treatment of on-site vs. off-site storage? What is your rationale for recovery of fuel inventory carrying cost through the fuel clause?**

<u>Answer</u>:

All fuel inventory carrying costs are recovered through base rates with the exception of coal inventory in transit or off-site storage. Pursuant to Stipulation and Settlement approved in Order No. PSC-05-0945-S-EI, Docket No. 050078-EI, dated September 28, 2005, PEF is recovering the carrying costs of inventory in transit. Item 16 on Page 22 states, "PEF will collect through the fuel recovery clause its carrying costs of fuel inventory in transit…"

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060001-EI

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
_______________________________/

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TELEPHONIC DEPOSITION OF:	CARLOS ALDAZABAL JOANN WEHLE BENJAMIN SMITH
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 362 Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 1:00 p.m. Concluded at 4:20 p.m.
DATE:	Wednesday, October 18, 2006
REPORTED BY:	JANE FAUROT, RPR Official FPSC Reporter (850) 413-6732

INDEX

MISCELLANEOUS

STIPULATION

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

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

confidential treatment under Section 366.093, under motions for temporary protective orders and a nondisclosure agreement. And we would like to simply caution all participants against disclosing any of our confidential information on the public record in these depositions.

This is not to say that anyone can't ask about this information so long as they don't -- so long as they do it in a way that doesn't actually disclose the information; for example, by reference to an amount on a certain line on a certain page without saying the amount. We would also like to request a stipulation of the parties that in the event someone inadvertently mentions during these depositions any information which is protected as confidential information, that we would instruct the court reporter to strike that from the transcript of the depositions. And that would be something that would protect all of us from violating confidentiality, including ourselves, in case we inadvertently say something that is confidential in the record.

And I would ask if the parties are agreeable to doing that.

MS. BENNETT: Certainly the Public Service Commission is willing to do that. Let's hear from the other parties.

MR. McWHIRTER: FIPUG says yes.

MR. BECK: Jim, this is Charlie Beck. That's okay with us, but I think we would want to wait on an item-by-item

A (By Mr. Aldazabal) My name is Carlos Aldazabal, and I'm the Manager of Regulatory Affairs for Tampa Electric Company.

Q And then Mr. Smith.

A (By Mr. Smith) My name is Benjamin Smith. I'm the Manager of Wholesale Power for Tampa Electric Company.

Q And, again, this is Lisa Bennett speaking.

I'm going to start with Mr. Aldazabal. As Manager of Regulatory Affairs, is it your responsibility to oversee TECO's projected recovery amounts under the fuel and purchased power recovery clause?

A (By Mr. Aldazabal) Yes. This is Carlos Aldazabal, and I do oversee Tampa Electric's cost-recovery for fuel and purchased power.

Q Very good. Then you would be the right person to ask what TECO's methodology for projecting annual fuel expenses would be?

A Again, this is Carlos Aldazabal. For the projection filing, we have a very comprehensive process where different departments are involved in compiling information where ultimately we prepare the final schedules based on the data that is computed.

Q All right. In your September 1st testimony, would you go ahead and pull that out and look at Pages 8 and 9 of your Schedule E3.

Q I'm sorry.

A That's all right.

Q Would you go ahead and answer that question.

A Would you repeat the question again, please?

Q Sure. Considering the commodity component of the price of natural gas, how do these prices compare with the current NYMEX settlement dated October 16th, 2006?

A And I assume you're talking about the NYMEX settlement as in the Gas Daily?

Q Yes.

A That's correct.

Q Well, and I think actually in Staff's 7th Set of Interrogatories you do sort of an analysis, if you will, in the question part of where you line up NYMEX pricing plus an adder for transportation and other commodity, or other costs, and sort of -- isn't that similar to what you're asking here?

A Yes, it is.

Q Okay.

A We actually have prepared, you know, a draft response to that. And it's not so simple as just looking at the NYMEX on its own. You have to take into account that while the prices have dropped in the near term months, we also have had hedges put in place at varying prices as part of our hedge program. And so you have to factor in the fact that those hedges will actually be settled and trued up as part of the upward movement, and it moved down about 40 cents the next day. So, you know, to take one moment in time, necessarily, and say that's going to be what the price is going to be over the next 16 or 18 months is really very difficult to say.

You know, we have not gotten to any kind of heating demand season yet, and so while, yes, the prices are coming down on the NYMEX, we have had very strong injection into storage, that has contributed to the price coming down. We have not seen a withdrawal season yet.

So while the prices on October 16th look like they, you know, have fallen, it's just as easy, with this volatile commodity, that it could go back up. And, again, at some point as we prepare our projections, you have to go with the best information that you have at the time. You know, we talk about it here at the company. At some point you have to put your pencil down and kind of go with the best projection you have at hand and look at where you are, you know, given all of the NYMEX information, what consultants are telling you, where storage is, you know, rig counts, all of that kind of information plays into how you best forecast natural gas in a very volatile market.

Q What factors would make you decide to reproject?

A Well, I think given, you know, in essence, we reprojected some last year. We had a very volatile gas market after Katrina and Rita hit, and that was such an anomaly that

A Yes, ma'am.

Q Let me ask you a question. Through hedging, have you backed in a price higher than the current forward curve?

A I don't understand your question.

Q I'm sorry. Have you locked in -- they're passing me a note -- have you locked in a price higher than the current forward curve?

A We have locked in prices higher than the current NYMEX strip, yes. And that is why you have to, you can't just look at the NYMEX by itself in a vacuum, you have to understand what other pricing we've already locked in.

Q Okay. So we've talked about hedging and we have talked about the winter supply. What other things does TECO look at in making its projection?

A Obviously, we use -- we use consultants in order to assist us in understanding what their views of the market will be, certainly out into the future. So that is definitely, you know, a factor taken into account. And we look at the volume of gas that we are going to be using; we look at our transportation logistics, where we're buying gas from, those types of things.

Q Okay. So I think it's fair to say that at this point TECO is not going to reproject based on a decrease in NYMEX prices, am I correct in making that statement?

A That's correct.

have any associated with that for 2007.

Q Okay. Next I'm going to ask you to look at Schedule E4, which is Page 14 of your direct testimony?

A Okay. I'm there.

Q It's Page 14 of 31.

A Yes. I'm there.

Q Okay. Is there a planned outage for Big Bend Unit 2 in May of 2007?

A I wouldn't know that. I can see that megawatt hours are lower than the other units in 2007, but as far as whether we have a planned, I mean, I'm sorry, it would be a planned outage. I don't know. That would be something that the resource planning folks would have to address. Bill Smotherman.

Q So I would ask Bill Smotherman?

A It does appear that there could be an outage at that time, but Bill Smotherman would be the person to answer.

Q I have about -- I have several more questions regarding planned outages for the Big Bend units. Would they all be Bill Smotherman's?

A The GPIF-related questions would pertain to Bill Smotherman, yes.

Q I guess my question, though, is more related to how do you -- when you have a planned outage, do you include that in your projections for the following year?

Q And would he know when the scrubber at Big Bend Unit 4 is being serviced? Is that Bill Smotherman, also?

A Again, Bill Smotherman would have to answer that. I'm not confirming that there are outages associated with the Big Bend SCRs. Bill Smotherman would have to answer that question.

Q All right. I think I'm going to switch to Mr. Smith. And, again, Mr. Smith, I want you to refer to your testimony for September 1st, Page 7, and also Schedules E7 and E9. I believe the Schedules E7 and E9 are attached to Mr. Aldazabal's testimony, so you might be needing to look over his shoulder at the same time.

A (By Mr. Smith) Okay, I'm there. This is Benjamin, I'm there.

Q Is the replacement power for the scrubber outages -- if you can answer this question -- the replacement power for the scrubber outages and the planned outages, are they included in the estimate of purchased power on Schedules E7 and E9?

A If we've purchased power going forward, then they would be in here, yes.

Q They would be in E7 and E9. The replacement power will cost more than the power generated at the Big Bend Units, is that correct?

A Typically, because the coal generation, the energy is low, typically the energy would be more on a replacement

Q So your projection does not include any purchased power for -- assuming you have planned outages, for those planned outages, is that correct?

A It doesn't have any prepurchases that we have done ahead of time, correct.

Q And it doesn't have any estimates of purchases that you may have to make?

A For each month of a filing, there are assumptions in the model of what market power may be on an hourly basis. And as economical, when the resource planners run the model, the model will select to buy or dispatch our own resources. In the projection, that is always the case. But on a forward basis, we have not gone out and secured a contract for purchased power for that '07 FCR outage. Does that make sense?

MS. BENNETT: I think I understand it. Give me just a moment. Let's go off the record for just a minute and let me ask staff if they have a question.

(Off the record.)

MS. BENNETT: Okay. We're back on the record.

BY MS. BENNETT:

Q I have a couple more questions for you, Mr. Smith, and it has to do with your savings calculation. So if you will turn to Page 5 of your testimony.

A This is Benjamin, I'm there.

Q Lines 19 through 25 and continuing on to Page 6, A Okay. Page 6. Yes.

Q How are Tampa Electric's gas storage costs associated with Bay Gas reported on the E Schedules? And when you're answering that, if you would explain where and why, and then we will ask the same questions for the A Schedules.

A On the E Schedules, it's included in the natural gas line items on the E3s, and it's going to be the exact same for the A Schedules.

Q Okay. Regarding natural gas storage, does Tampa Electric charge carrying costs on working gas to the fuel clause?

A That's actually a question for Mr. Aldazabal.

A (By Mr. Aldazabal) This is Carlos. No, do we not recover any kind of carrying costs for natural gas.

Q Okay. Back to Ms. Wehle. A different set of questions. This is on natural gas forecast drivers. If you will turn to Page 11 of your testimony, Lines 6 through 17.

A (By Ms. Wehle) Okay, I'm there.

Q You still expect an increase in natural gas prices in 2007?

A Is that a question?

Q Yes.

A Do we expect that?

Q Yes, that's correct. Do you still expect an increase in natural gas prices in 2007.

In general, though, the effect on hedges that we have in place for Tampa Electric, we have incurred some losses in 2006. And, you know, likewise, when prices were rising in 2005, we incurred quite a bit of gain, as well. So, again, it just depends on the volatility and the movement of the market.

Q That's all I needed on that.

I apologize, but I do have one more question on -- I think it's probably related to natural gas forecast drivers.

A Okay.

Q Back to Page 11, I think, Lines 14 and 15, you talk about delayed liquefied natural gas projects. Can you tell me about those?

A Yes. And, again, I'm not an expert on LNG facilities, but there are quite a few projects that were on the drawing board, if you will, for LNG facilities around the different coasts of North America. And a lot of those projects have either not gotten the financing or haven't gotten off the ground, and so what had been anticipated as a supply increase on the part of LNG into the United States has been somewhat delayed.

Q Okay. The next set of questions I think is probably going to be directed at Mr. Aldazabal.

A (By Mr. Aldazabal) Okay.

Q I need you to -- it's going to be about Schedule D sales, so I need you to look at your A6 January 2005, your

Q Can you tell me how or where in the reporting requirements are Separated Schedule D sales reported or accounted for?

A As far as on the A6 schedule?

Q Yes.

A It's on the bottom of Schedule A6 on the August 1 -- it's reflected on the bottom of that schedule.

Q Okay.

A And that reflects the megawatt hours as well as the fuel costs for that sale.

Q Okay. In your response to Staff's Interrogatory Number 4, you used the term system incremental fuel cost. I think you have explained it, but would you go over that term again for me?

A Yes. It's the incremental fuel associated with making that specific sale. If our fuel cost is at a certain number and to make that sale it would raise that to a higher number, the fuel costs associated with that, that increment is what is passed on as part of that sale.

Q And forgive me, I'm not an accountant, so I'm going to ask a question that I hope makes sense. Can you tell me how is that calculated, how are the increments calculated or determined?

A Benjamin Smith could probably better answer that question.

Q Are the costs associated with Schedule D sales that are the subject of your response to Interrogatory 5 reported in your A6 Schedule in Column 8, also?

A That Column 8 would have -- not only the fuel charge, it would also have the total sales price associated with that sale, so it would have all adders.

Q What about some of the costs like capacity, O&M, transmission, emissions allowances, where are they accounted for in association with those sales, both jurisdictional and nonjurisdictional?

A Are we still referring only to Schedule D?

Q Yes.

A This is Carlos again. The incremental O&M associated with the Jurisdictional D would be pulled out of Column 7 and booked against operating revenues consistent with Order 1744, I believe is the order number, and all other components would -- I'm sorry, only the fuel component would be reflected on Column 7. And there is no emissions on the PRECO or Hardee deal because, like I said, it dates back to 1992 before we had any kind of emissions trading.

Q Okay. In the January 2005 A6 Schedule, and also referring to your response to Staff's Interrogatory Number 6, does the total for fuel adjustment in Column 7 -- I think we just answered this -- include emissions allowances?

A No, it does not. That is removed and included

A Okay.

Q And if there is another panel member who is better able to respond, please direct me to them.

Would you describe in detail the steps that TECO has taken to implement the Hill and Associates Study, which was the subject of the Order 04-0999, and I'm hoping that you will supplement. I know you have responded in an interrogatory, but if you can supplement that I would appreciate it.

A And I believe it's part of the discovery, we've responded with POD responses regarding quite a bit of correspondence between us and the railroad, as well.

Once we had completed the Hill and Associates Rail Study, we have been in conversations with the railroad consistently since the study was complete, actually even before that, to try and get some short-term rates to our facility and to other existing rail facilities in the state of Florida. We have tried time and time again to try and get them to give us an indication of where they think rail facilities will exist in the Tampa Bay area. We engaged with them on a number of occasions to try and talk with them on long-term efforts on what their responses would be to our next RFP for transportation. And, you know, and even during the hurricanes we turned to them for assistance and tried to understand what their capabilities would be as a transportation alternative, given the fact that Katrina had damaged our terminal facility of late, what we have done is, again, met with the railroad, toured the facilities, showed them the construction that is actually going on now to meet our environmental requirements on a go-forward basis, and really ask them to assist us with developing ideas of potential projects down there.

What we all have determined out of this is that there is not a lot of space left down at Big Bend to really put a workable rail solution in there. You know, that's not to say that, you know, something couldn't be done with adjacent property if we were to look at it.

What we have done, though, is engage them to try and look at an existing facility in the Port of Tampa called their CSX Rock Port Facility, which is a state-of-the-art facility that really is underutilized at this point, and try to come up with a game plan of rather than build something 20 miles down the road, why not let's use something in a more efficient manner with an existing facility that has the capability of receiving rail. It has three loop tracks, and it has berthing facilities there as well to not only accept rail on an import capacity, but also potentially look at how those berthing facilities could be used for, you know, export.

We are actively in discussions with them. Because I think right now Rock Port is probably, in Tampa Electric's mind, is the best alternative for us. It's an existing facility and it's underutilized. Right now the products that

And so if there is anything else out there that folks are considering, be it, you know, maybe Jacksonville on the east coast might develop a coal terminal there, to be able to, again, receive waterborne as well as rail facilities, or if there is something else that exists in the Tampa Bay area, you know, it sort of remains to be seen. Absent that, we don't really know of anything that's on the drawing board, per se.

Q I'm going to switch back to the wonderful A Schedules, and this time I'm going to ask that we look at Schedules A7 and A9 for January 2005.

A Who is this for?

MS. BENNETT: I'm sorry, this is for Mr. Aldazabal, I believe. And I'm going to ask that the court reporter enter these in as 4 and 5. A7 would be 4, and Schedule A9 would be 5.

(Exhibits 4 and 5 marked for identification.)

MR. ALDAZABAL: Okay, I'm there.

BY MS. BENNETT:

Q Mr. Aldazabal, give me just a moment more with Ms. Wehle.

A (By Ms. Wehle) Actually, Lisa, if I might just add one more thing to my last response.

Q Okay.

A Absent, you know, looking beyond Tampa Bay, if you will, you know, what we need to consider, and that's why we're

Q In Column 8 of the A7 schedule, what types of costs are included?

A Column 8. The total cost column?

Q Yes.

A I'm sorry, total fuel adjustment cost. That would be the total fuel costs associated with making that purchase would be reported on Column 8, which includes transmission. It's an all-inclusive cost.

Q Can you be more specific for me. Just pretend like I'm new to this job.

A All-inclusive would mean all costs associated with bringing that power to a tie point within Tampa Electric's service area.

Q So it would include transmission costs obviously?

A Yes. All costs.

Q O&M?

A Yes. Any O&M -- well, the O&M would be part of the margin, I'm assuming, that the company selling us the power would have. They would probably not break it out on the invoices.

Q Okay. What type of costs are included in Column 5 of the A9 schedule?

A Column 5 is the same thing as Column 8 on the A7 Schedule. It is an all-inclusive cost associated with making that economic purchase.

have happened is it should have been moved out of the fuel and into the capacity clause. The net effect, I believe, was 600-or-something dollars due to separation.

Q And has that been corrected for each year from 2005 on?

A Yes, it has been corrected.

Q That's all I have right now on audit findings. Sharpen our pencils, and let's go to over and underrecoveries issue. And I'm going to focus right now on the reprojection filings for 2005.

Reprojections were made October 14th, 2005, is that correct?

A That is correct.

Q And they were made after certain catastrophic weather events affected the market, correct?

A That is correct.

Q Even after the reprojection filings, it appears that TECO is significantly underrecovered for the last four months of 2005. And I guess I would like for you to comment on, first of all, are you aware of what that underrecovery is?

A Yes. The underrecovery for 2005 related to our actual/estimated filing, it was $106.5 million.

Q In relation to the orders from the Public Service Commission, that is Order 13694 and 980691 as applied to the end of 2005, were you 10 percent underrecovered at that

Q Sure. When did you become aware that instead of the projected underrecovery, and I'm not great with numbers, but the one that you projected in August 8th was about 145 million. You actually were underrecovered 200 and --

A 54.

Q 54. When did you realize you were underrecovered 254 million?

A We would have realized that in late January once we actually trued up the month of December that we were 254 million underrecovered for the year, which would have been included in the true-up filing.

Q Okay. Did you notify the Public Service Commission in January of January of 2006 about this additional underrecovery?

A Well, we file monthly A Schedules notifying them where we stand as far as an underrecovery position. But again when we determined the 10 percent threshold calculation, our interpretation is that it only applies for the current period. So by notifying the Commission on July 22nd, we felt that we were covering the entire 2005 period as far as an underrecovery, that we were more than 10 percent underrecovered.

Q So how often, for purposes of the order, do you evaluate under and overrecoveries?

A We monitor our position on a monthly basis, however, MS. BENNETT: Okay. Give me a minute to have it in front of me. I'm just making sure I have a copy for the court reporter. I'm going to ask that the court reporter include this as Exhibit 6. Do you have any objection?

MR. BEASLEY: No objection.

(Exhibit 6 marked for identification.)

BY MS. BENNETT:

Q Okay. TECO based its petition on a September 1999 through December 1999 final true-up underrecovery of 8,662,661, and a reestimated year 2000 underrecovery of 28,918,539. Am I correct in that conclusion?

A I believe this was the first time we had a midcourse correction when we went to the annual filings. I wasn't in the department at that time, but it appears that that was the interpretation of the order. I don't know the reasoning behind that interpretation at that time.

Q So in 2000 it is correct that TECO included two years in calculating its underrecovery or overrecovery?

A In notifying the Commission, it does appear that their 10 percent threshold was based on the prior period true-up plus the current year underrecovery. But we have had subsequent midcourse corrections where that has not been the case, where it was only been based on the current period underrecovery amount.

Q All right. I think I've got another one of those objection to that one?

MR. BEASLEY: No, no objection.

MS. BENNETT: And then, again, February 24th, 2003. I've got Document Number 1866. Any objection to that being entered into as Exhibit 8?

MR. BEASLEY: No objection.

(Exhibit 7 and 8 marked for identification.)

BY MS. BENNETT:

Q Exhibit 7, the 2001 midcourse correction?

A Yes, I am there.

Q Did you actually have an under or overrecovery the prior year?

A There was an underrecovery from the prior year.

Q Did that get included into the midcourse projection or midcourse correction letter that was sent February 9th, 2001?

A It was included in the notification. However, as far as setting the threshold, the 10 percent threshold, that was not part of the calculation for the 10 percent threshold where we had to notify the Commission. It was not included in that calculation.

Q Did you actually include it in the correction?

A Yes, we did.

Q What about the next exhibit for the 2003, did you have an underrecovery the prior year?

Q So we're still in agreement?

A Yes.

Q In that petition with so much of the estimated 2001 overrecovery being for the current year, isn't it true that TECO would have been beyond the 10 percent threshold even without the 23,129,476 from the year 2000?

A Yes, that is correct. And that is exactly why we notified the Commission at that point, we had crossed the 10 percent threshold. Only looking at the 63,205,914 for the current period.

Q Now, let's go to the 2003 midcourse petition?

A Okay, I'm there.

Q In early 2003, you reestimated -- TECO reestimated 2001 -- 2003 expenses, I'm sorry, or actual fuel costs. They were 11 percent greater than forecasted jurisdictional system fuel costs for the period, and that is in Number 6 on Page 2.

A I am there.

Q The projected underrecovery of $89,272,063 consisted of 28,662,327 from the end of 2002 and 60,609,736 estimated for 2001. That's Number 6 and 7?

A That's right.

Q I'm sorry, estimated for 2003, not 2001. That is 6 and 7 on Pages 2 and 3.

A Yes.

Q Okay. And TECO petitioned to modify its recovery

A No, I would not agree. The 11 percent was strictly a trigger that would trigger us to notify the Commission that we were more than 10 percent underrecovered, or we were projected to be more than 10 percent underrecovered.

MS. BENNETT: Give me a couple of minutes. Let's go off the record.

(Off the record.)

MS. BENNETT: I'm back. And are you all there with me still?

MR. ALDAZABAL: We're still here.

MS. BENNETT: Are we ready to go back on the record?

MR. BEASLEY: Yes.

BY MR. BENNETT:

Q My first question is on the prior years, the 2001 or 2003, this is a hypothetical, we have already discussed that your opinion is that the order does not allow or does not require you to go back to the prior year. So my hypothetical is what if the prior year you had an overrecovery and not an underrecovery, and so the following year you have a 10 percent, say, or an 11 percent underrecovery. Would you have filed a midcourse correction letter on either one of those occasions?

A (By Mr. Aldazabal) This is Carlos. We would notify the Commission that we were more than 10 percent underrecovered in the current period, but we would probably not seek a midcourse correction, obviously, because we were overrecovered still be reviewed and subject to check. And my guess is maybe a week, week and a half after the close-out date. So it would have been impossible to include in an October 14th filing date.

Q So you are saying between October the 7th and the 10th you would have had the final numbers?

A No, it depends on -- I'm talking about seven business days. So it would have been after those dates. And, again, we would have had a gross amount. We wouldn't have had the detail associated with that underrecovery.

Q And there was nothing in the gross amount to cause you some concern about your reprojection testimony?

A It would have been one month's worth of information. And, again, we would have to -- we have to put our pencils down at some point. So even if we didn't know at that time, there is nothing that we could have done at that time to include the September information in the reprojection filing.

Q You filed your A1 schedule for September 2005. Would that have included your gross or your net amount?

A I'm sorry, are you referring to the reprojection filing?

Q No, I'm sorry, I am talking about your A1 schedule for the month of September 2005.

A That would have included the actual results for September.

Q And when was that filed with the Public Service

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however, we had significant gains in those months on our hedge plan that were also included. And so given those two factors added together on a net basis that resulted in the actual gas forecasts that we show on the reprojection of October 14th.

Q Let's go back to the letter dated July 22nd, 2005, and that is part of your interrogatory response.

A (By Mr. Aldazabal) Yes.

Q What is the relevance of the letter to the large underrecoveries that occurred in the last four months of 2005 after Hurricanes Katrina and Rita caused increased natural gas prices and purchased power prices?

A This is Carlos. The relevance of the letter is that on July 22nd we were just notifying the Commission that we had crossed that 10 percent threshold, that we were forecasting to cross that 10 percent threshold by the time we got to December 2005. And it doesn't necessarily tell you what -- well, it tells you what we forecasted that underrecovery to be at the end of December 2005 based on current data. But, again, we are just notifying the Commission that we were above that 10 percent threshold. But I believe even in the letter we mentioned that we are going to be including this information in our reprojection filing which was coming up in a couple of weeks in August.

Q Okay. And this may be repetitive, but I'm going to ask it and let's see. You can tell me I have asked it, if I

A No, there is not, in my opinion.

Q Okay. Bear with me. We're going to try and work through this table, and I've got Sid Matlock sitting right at my left-hand side to help me as we go along, but there was a staff created Table 1 that we faxed to you?

A Yes, I have it.

Q And that will be Exhibit 9. And there are two pages. Do you have both pages?

A Yes, I do.

Q I do have a correction, and that is at the top under jurisdictional fuel revenue. Under the word dollars it should say 2007, not 2006. Can we make that correction?

A Where, under what column?

Q I'm sorry, under jurisdictional fuel revenue you have got dollars, megawatt hours, and cents per kilowatt hours. Immediately under the word dollars at the top left-hand corner of the page it says 2006, and then (d)(e).

A Yes.

Q That needs to read 2007. Can we make that change here and there?

A Okay. It is made.

MS. BENNETT: Do we have any objection to entering this as Exhibit 9?

MR. BEASLEY: We don't.

(Exhibit 9 marked for identification.)

we look at whether the actual fuel costs, that's the term used in the order, are 10 percent greater than or less than its projected fuel costs. And that's also from the order. When we go back to the A Schedules, A2 Schedules, those actual fuels costs are referred to as expenses on the A2 Schedule, is that correct?

A Yes, that's correct.

Q And the projected fuel costs are revenues on the A2 Schedule, is that correct?

A I'm sorry, could you repeat that again?

Q Maybe. Yes, I can.

I'm trying to apply the orders, the language in the orders to what is actually used on the A2 Schedule. My understanding is that when the order says actual fuel costs, the A2 Schedule translates actual fuel costs to the terms expenses. So on the A2 Schedule that would be expenses, is that correct?

A That is correct.

Q And projected fuel costs, when that term is used in the two orders, on the A2 schedule those are revenues, is that correct?

A Well, I don't think so. Projected fuel costs would be what you are projecting to happen for the remaining portion of the year. The way we look at it is we look at it based on the factor, the all-inclusive factor at the bottom of, I let me give you -- it is 935 of the E1 on a dollar basis for 2007, which is $1.177 billion. We would divide the underrecovery amount that we are projecting for 2007, if we have did a reprojection by that amount to set the threshold. But it is just simpler to do it on the factor.

Q Okay. Well, just for a month, then, isn't overrecovery equal to -- over or underrecovery equal to revenues and expenses?

A For one month, yes. Yes, you would take revenues and you would subtract expenses plus any interest component and that would give you your over or underrecovery for that specific month.

Q Okay. I'm going to ask that you look at Column H of our table, or you could look at Column 3 on your A2 Schedule as I'm asking this question. Do you agree that the denominator of the overrecovery percentage should be the jurisdictional fuel revenue applicable to period, and that would be according to the order, the orders, 13694 and 980699?

A The denominator in the calculation of the 10 percent?

Q Correct.

A Where is it on the -- I'm sorry, what column is it on the A Schedules?

Q I'm sorry, on the A2 Schedule it is Column 3. I'm sorry, Row 3, not Column 3.

A Give me one second.

MS. BENNETT: Again, I want to go off the record. I think that this concludes our questions, but I want to make sure that I have covered everything that PSC staff wants to cover, so give me just a minute. I am going to go off record and put us on mute again.

MR. BEASLEY: Sounds good.

(Off the record.)

MS. BENNETT: Well, I have great news. We are back on the record. The Public Service Commission has no further questions of this panel, and I thank you very much for your time. However, I understand that Mr. McWhirter from FIPUG has questions.

And before we start with the cross-deposition, Mr. McWhirter, can you give us an idea of how long? Do you have a few questions or should we take a break and get back and start with you?

MR. McWHIRTER: I have 42 minutes of questions.

MR. BEASLEY: I've got a 4:30 flight, so if we get started right now --

MS. BENNETT: Can we take a five-minute break?

MR. McWHIRTER: Certainly.

MS. BENNETT: We'll come back at five minutes until 3:00.

(Off the record.)

MS. BENNETT: We are ready to go.

for the year, for the average of those sales is $27.11 per megawatt hour, whereas on your Schedule E1 you show that it costs you about $44 to generate electricity and your average cost after you add in the various other things attributable to the factor runs up to $58.90. Where does this power come from that you sell to Seminole?

A Typically, the power sold comes from our own generation, and comparing those two prices can be a bit misleading because typically the sales are going to occur during periods that are economic for us to sell, so it could be on an off-peak period. Most likely it is going to be during an off-peak period, and any purchases that are going to be made are probably going to be made during our peak load period which would be at a much higher price.

Q I don't have current factors before me, but my recollection of the last time that I looked at this, Seminole was buying from you 100 percent of the time because it was economically profitable for them to do so. Do you know when their sales occur currently?

A Benjamin Smith could probably better answer questions associated with the actual sales to Seminole as far as timing.

A (By Mr. Smith) You are talking about that --

Q You will have to speak up, Mr. Smith.

A (By Mr. Smith) This is Benjamin Smith. On the E Schedule, E6 you are referring to that line that says Seminole

Q Does Tampa Electric power go through Hardee in the pricing mechanism to Seminole?

A I do not know.

Q Do you know, Mr. Smith?

A (By Mr. Smith) I do not know. This is Benjamin. I do not know.

Q And as I understand it, formerly there were 145 megawatts of Big Bend 4 that were separated for the Seminole sale and that is no longer in existence, and this sale is a straight wholesale sale?

A (By Mr. Aldazabal) This sale here is actually a territorial dispute that's actually a retail service sale that dates back to 1992, so it is totally different than the Big Bend 4 separated sale, yes.

Q Is there any separation of Big Bend 4 at this time for any party?

A No, there is not.

Q And the only separated sales you have are the New Smyrna Beach sales?

A That's correct.

Q Is there any way I could request a late-filed exhibit to give a narrative explanation of why it is that the sales for Seminole that are anticipated for the year 2000 are coming in at substantially less than your average cost of production?

A For 2007, yes.

AR1 contracts, which are separated sales. The Big Bend 4 separated sale is no longer in existence, but we do have five AR1 agreements that are not reflected on the fuel filings. They are completely different. They are part of the AR1 FERC tariff. So the fuel charge is calculated completely independent, and it is part of that separation factor that we calculate.

Q Can you tell me what the AR1 Schedule is?

A It is a tariff with FERC, and there are five different customers who are under that tariff. They are Fort Meade and Wachulla, Progress Energy, St. Cloud, and Reedy Creek.

Q And you think that Progress Energy also shows up on that?

A FPC is one of the five.

Q They now call it PEF in modern times?

A I'm used to the FPC name.

Q Okay. And when was that separated sale entered into, and when was it approved by the Commission?

A Which one, the Progress Energy?

Q Progress Energy, yes.

A I don't know. It has been in existence quite awhile. I know it is from the '90s.

Q How many megawatts of power are separated under your AR-1 schedules and where would I find that on file with the

A For that month.

Q Is separated. And that is extracted from your rate base and recalculated how often?

A That's done on a monthly basis.

Q So that changes your return each month?

A Yes, it does.

Q I would like for you to look at the second page of that document I handed you, which is Bates stamped 43 from your E1 Schedules filed with the Commission. This is an extract of Schedule E7, which is your purchased power. And I note, maybe this is for you, Mr. Smith -- (pause) -- I'm still with you, I'm just meditating. In April of 2007, you contemplate paying Hardee Power Partners $3,300.13 a megawatt for power, megawatt hour for power?

A (By Mr. Smith) This is Benjamin. I see that. More than likely there is a fixed O&M component in there that's making that rate arbitrarily high.

Q Do you have an obligation to purchase a certain amount of power or pay for a certain amount of capacity to the Hardee Power Partners each month?

A For Hardee we do have a capacity payment that we make to Hardee, but as far as the obligation to take energy, we have no obligation to take energy.

Q The last time I visited with you about this contract, I understood that the contract had expired at the time of the

A Right.

Q And you have an obligation to pay somebody else for an additional 75 megawatts?

A This is Benjamin. Let me go back and say it a different way. Under the Hardee contract, Tampa Electric Company pays a capacity payment.

Q Right.

A When the Hardee contract initially began, it involved roughly the 295 megawatts. Around the year 2000, Tampa Electric took an option to build or have access to an additional 75 megawatts. Before Tampa Electric's option, the Hardee deal involved Tampa Electric having 40 percent basically payment obligation and Seminole having 60 percent payment obligation. The 2000 CT that was put on the ground is 100 percent Tampa Electric's obligation.

Q But now the 295 is now 100 percent TECO, is that correct?

A The 295 will continue to be Tampa Electric and Seminole's shared obligation through the year 2012.

Q So you have an obligation for 60 percent of the 295?

A For 40 percent.

Q 40 percent, okay. And you don't know whether Seminole takes power 100 percent of the time, or 10 percent of the time, or just during your off-peak periods, is that correct?

on the information that is provided from a comprehensive model that models all these purchases.

Q Okay. And the pricing of the power, is that incorporated in the model, as well?

A That is incorporated in the model.

Q And you would glean from the information that this has got to be substantially off-peak power?

A That and Benjamin alluded to a fixed charge component embedded in that price. So obviously if you have a very small amount of megawatt hours purchased it kind of distorts the cents per kWh.

Q No, I am looking at the sales.

A Oh, you're looking at the sales? I'm sorry. On 24 of 31?

Q I'm looking at page -- yes, 24 of 31, Bates stamp 42, and it shows for the year the average price is going to be something like $27.11 on your sales to Seminole.

A Yes. And, again, that is a totally distinct sale from the purchase. That is a sale to Seminole for PRECO where they turn on and sell it to IMC, so it's part of that retail service agreement.

Q I see. This is a sale to PRECO as well as to Seminole for its own utilization?

A Yes.

Q And you say there is a dispute in connection with guess that's what other people do and you're not interested in making money on hedges, is that correct?

A Well, that is not the purpose of our hedge program. Whether or not others choose to do that as part of their objective, our objective, as you mentioned, is to minimize volatility of prices and to provide as much reliability as possible. With that there are going to be -- a fallout of that is you are going to incur gains or losses associated with trying to minimize that price volatility. Any gains or losses that are incurred flow back to the customer. So when you say making money, I'm assuming you are saying gains, those would all be for the benefit of the customer.

Q So that is something that customers ought to be looking for, is that right? But, as a matter of relative importance, how would you relate reliability to volatility? Which is more important to your risk management team?

A They are equally important. Obviously, you can have prices that are extremely volatile. But we are in the business of making electric power, and so regardless of what the prices do, if I don't have a reliable supply of, for instance, a fuel source, or in Benjamin's case a power source, it really doesn't matter what the price does. So they are equally important from a hedging perspective. Again, you know, we focus a lot on trying to minimize price volatility and providing more of a smoothing effect on pricing yet still send the appropriate the storage mechanism will continue to help us decrease some price volatility.

Q Your average daily consumption, I guess this is not confidential, that is around 5 million MMBtus a day?

A Again, it depends on which season we are talking about, but it can be in the neighborhood of over 200,000 a day. It can be up to 300,000 in a very peak period, and it can be quite a bit less than that in more of the shoulder months.

Q And we're talking MMBtus?

A Yes.

Q And your storage capacity, what is that, if that is not confidential?

A Did I not have a confidential in there?

Q I don't know.

A I don't know that it is. If you will give me a second, I can actually find out whether we marked it as such. I'm trying to remember who asked the question in the interrogatories.

Q If that is going to take you too long to accommodate, Jim, I don't mind moving ahead.

A Okay. But, again, we responded to that question, and so obviously we have that data available.

Q If I did my homework I could probably find it, right?

A Actually, here it is. It's Staff Data Request Number 1, and it was not marked confidential. The initial amount of recovered. We would not have any kind of return component associated with that inventory.

Q But you would in base rates?

A Yes. For coal. If it is a new item, such as gas, it would not be part of base rates obviously because it is a new -- gas would be a new commodity for us, so there is no carrying costs for gas. But, again, it would be a base rate item.

Q Is that gas available for sale in the wholesale market as well as the retail market?

A (By Ms. Wehle) You mean if we were to take it out of storage and sell it on the wholesale market?

Q Can you do that?

A Tampa Electric doesn't typically. We utilize that for our own purposes.

Q You don't engage in trading natural gas physical contracts?

A Not typically, I wouldn't say that.

Q Did you tell me what costs are included in the fuel clause for Mobile Bay?

A It would be the associated demand charge, any charge associated with an injection or withdrawal, and then any fuel charge, like a fuel usage charge for any compression activities and the like. So very, very related to the movement in and out of the storage facility.

interrogatory, there are five people in the risk management department, seven of the 15 employees in fuel management, and three people in the settlements department deal with the hedging activities, is that about right?

A Yes. As part of their normal on-going activities. That is not the only thing that they do, but hedging is a part of their function.

Q What, if any, component of the salary of these people is included in your fuel cost surcharge?

A Well, if you recall the hedging docket back in 2000 or 2001 that talked about incremental charges for establishing a hedging program?

Q Uh-huh.

A There was a benchmark that was set by each company, each company had a different one. These seven individuals record their time on hedging activities and anything over and above that benchmark has been included as hedging activity costs that have flowed through the fuel clause over that five-year program period which I think ends at the end of this year.

Q It's what this year?

A I think it ends at the end of '06, if I remember correctly.

Q It ended at the end of '06, so you don't charge anymore?

covered through your fuel cost-recovery --

A For 2007.

Q Okay. Now, who is it that actually pulls the trigger on hedging activities, somebody in the fuels department or somebody in the risk management department?

A There's someone in the fuels department that actually engages in the transaction and talks to the broker or the financial institution or whoever we are actually putting the hedge on with.

Q Now, you do hedging for both Tampa Electric Company and the state's largest local distribution company for the sale of gas, is that correct?

A It is done out of the fuels department, that is correct.

Q And do you also manage risk for your Guatemala operation?

A Not really. If they were to come to us and ask us to actually put on a transaction at a particular price, you know, we might call the broker and actually get that transaction done, but the actual decision to do that at a given price is all done by the Guatemala people.

Q Do you hedge coal?

A We refer to it as a physical hedge, because there are contracts that we have entered into for fixed pricing and so we consider that a physical fixed price hedge.

Sebring facility and we have CTs at Big Bend that use Number 2, or the light oil, as well as our Polk facility has oil backup.

Q And you have two new CTs coming on at Polk Number 1 in May and June of this year?

A Polk 4 and 5?

Q Polk 4 and 5, yes.

A Those will be installed in '07.

Q '07?

A Yes.

Q Did I say '05? That shows how far behind I am.

A Those are gas CTs.

Q Here is something that has always puzzled us a little bit. When the Commission went to an annual fuel factor as opposed to what we did in the past every 60 days and then every six months, the purpose of that was to reduce volatility. Now that we have an annual fuel factor, why is it necessary to reduce fuel volatility from the customer's viewpoint as opposed to the utility's viewpoint?

A Well, I don't really understand your question. Obviously in order to -- we feel as though we have a responsibility to try and send the best pricing to our customers, and also as part of the hedging docket if you remember it really never came into being that the volatility of natural gas was such a huge deal. The winter of 2000/2001 when you started to see the price spikes in natural gas and providing a less volatile price signal than the ups and downs of, say, a spot market like that. And we feel like the hedging program that we have in place currently does just that.

Q Doesn't the one-year fuel factor protect customers from that kind of volatility?

A As long as that fuel factor predicts exactly what is going to happen in the natural gas market or whatever the commodity market is. You know, possibly -- Carlos, do you have any thoughts?

A (By Mr. Aldazabal) I think that was the intent. You said dramatic (inaudible) can't possibly be contemplated in the fuel factor. You are going to have extreme volatility if you are not doing some kind of hedging on the gas price side. You would be going in for numerous midcourse corrections.

Q What about the duration of your hedges in the gas market? You changed that duration over a period of time. What's the thinking on the background of that change?

A (By Ms. Wehle) To start to layer in some hedges out into the future, to not be short-sighted in our view, include activity that may be out longer than just the fuel period or fuel factor period that we're currently under. Really to kind -- to lock up the pricing out. As you can see, some of the other utilities go out even further than we do with some of their hedge programs. You know, you have to remember that Tampa Electric is sort of new in this game with our Bayside

A Okay.

Q No, it's on your first production, I'm sorry. It's a document that is called current TE plan. That was your risk management plan.

A I don't know that I have that with me.

Q Do you want to look at what I am looking at?

A Oh, I'm sorry, I do have that. Okay.

Q Okay.

A Page 13?

Q Is that the plan that is still in place?

A Well, my Page 13 is different than your Page 13.

Q This was the plan that was adopted in December of 2005. Why don't you look at what I've got here.

A This was the plan that was in place prior to December of '05.

Q Okay. And that is --

A Because of that. That is because of the term limits.

Q Then the next page is an approval request. It says that was submitted to your RAC.

A That's correct.

Q Is this the plan that is presently in place?

A That is correct.

Q And can you tell me in general terms without impacting confidentiality how the old plan compares to the current plan?

term. So, in other words, let's say for December of this year, we would want to be at that first bullet point, minimum, over time, layering in hedges over time. It is not, you know, in one fell swoop do you really make those hedges.

Q Did you give any additional information to the RAC? The RAC is --

A We call it the RAC.

Q Did you tell the RAC any more than you just told me as the rationale for moving from the December 5 plan to the current plan?

A I think what we told them was in addition to that, you know, the December 5 or prior to December 5 plan was sort of our plan as we got into hedging activities, and we felt like the newer plan was much more in line with where we want to actually lock in volumes and prices for the customer going out into the future. Given the fact that we had -- in the prior plan we had limited counter-parties to deal with, and over time we actually added a whole lot more counter-parties and creditworthy counter-parties to actually conduct hedges with.

Q Now, if somebody is buying common stocks, they go to a stock exchange and the NYMEX, the Commodities Exchange.

A That's correct.

Q And does the exchange approve the creditworthiness of the people that are participating in that exchange?

A We do not do exchange traded type of arrangements.

to be conservative, counterparties that we have ISDAs with. That's not to say that we necessarily engage with every one of those, but we have quite a few versus at the infancy of our program when we started.

Q Are any of these trading partners affiliated in any fashion with Tampa Electric or TECO Energy to your knowledge?

A No, they are not.

Q Is part of your program to ensure that there are no affiliations?

A I can't think of one that we would have that would even suffice as an ISDA counterparty underneath the TECO umbrella.

Q These people actually own gas or are they financial institutions that are gambling -- (inaudible)

A Some of these people are actually gas production companies and some of them are (inaudible) counter-parties that deal with (inaudible) --

I wouldn't say that they are -- you know, I can't characterize our activities as gambling in the futures market, but they are financial institutions.

Q Of your counterparties, what percentage are people that own gas and what percentage are financial institutions?

A I couldn't give you that, John, off the top of my head. If you want us to file a late-filed exhibit, we would be happy to do that.

plan that again could serve the customer well.

Q Did the Peoples Gas division engage in hedging before 2003?

A Yes.

Q They've done it over the years?

A That's correct.

Q How many years did they do it?

A I don't know, sir.

Q You mentioned that the difference between the price that appears in Carlos' exhibits and the NYMEX is based primarily on the transportation costs, and that's around a buck or less?

A Give or take, depending on, again, the utilization of that transport that we have under contract, and that is not the only component. I mean, there is fuel and usage charges and there's storage fees, and there's the actual commodity costs, of course, and the gains and losses on the hedge program.

Q The gains and losses probably constitute the principal difference, would you say, or not?

A No.

Q The principal difference would be transportation?

A As far as the dollar is concerned?

Q Yes.

A John, that is going to depend on every single (inaudible). That is really difficult to say.

MR. BEASLEY: Okay. I am just going to miss the flight, that's all right. I don't mind. I've got to get where it's quiet.

BY MR. McWHIRTER:

Q All my next questions have been crossed out because I understand you changed your answers.

A We corrected our answers.

Q Okay. What was the nature of the correction?

A Yes, an administrative typo, if you will. The underlining spreadsheets that supported the answer when we cut and pasted them into the actual file document, which was a Word document, we pasted them in the wrong one. So we apologize for that, but we knew once we saw and were kind of going back over our responses that those were incorrect, and we had to get them corrected.

MR. McWHIRTER: I'm going to try to speed -- Jim, is there any hope of you getting to your plane?

MR. BEASLEY: I don't know. Just take all the time you need. That's fine.

MR. McWHIRTER: Okay. Well, I'm going to try to accommodate you the best I can.

MR. BEASLEY: Okay.

BY MR. McWHIRTER:

Q I would like you to go, if you will, to FIPUG's first set of interrogatories Number 5, and at Page 2 of 2. And this people?

A Typically that's done in the fuels management area. We do pass along numbers, again, according to at what volumes the model turns out.

Q And this is a computer model, it has a lot of parameters going into it?

A That's correct.

Q Give me a quick list of some of the parameters that go into the computer model to establish your budget?

A (By Mr. Smith) This is Benjamin. The type of items that go in there are the fuel cost, expected load that you need to serve, planned maintenance schedules, and availability, things like that.

Q And this has to do with your price of gas and your price of gas changes with maintenance?

A (By Ms. Wehle) It can change, again, based on -- yes, on maintenance and, again, on transportation contracts of which we have contracted for some of the gas and those kinds of things.

Q And does the hedging team use a different model than the budget team or does it use the same model?

A They're separate. And it is not really a model, per se.

Q What is it?

A A review of the current market. And it is according

Q Can you confirm that the average hedge price that you paid during that period of time was greater than the budget forecast from your budget department and what actually turned out from the settlement prices?

A Yes.

Q When you talk about settlement prices, do I understand that what happens is you buy in the spot market and that is what you pay for the gas, but then your hedge partner reimburses you for the differential between the hedge price and the actual price?

A And the final settlement price on the NYMEX, that's correct.

Q And if it goes the other way then you pay?

A That's correct.

Q And what you pay is then charged to the fuel clause?

A That's correct. As well as the reimbursement, the cash that flows our way is flowed through the clause. And that constitutes the gains or losses.

Q I want you to go back to Interrogatory Number 3, and this is on Page 9 of 21 pages.

MR. McWHIRTER: And, Jim, this is all confidential stuff, so I'm going to be very careful.

MR. BEASLEY: Okay, good. I appreciate it.

BY MR. McWHIRTER:

Q What is this page?

Q Yes.

A I was on Bates stamped 9, I'm sorry. August through December?

Q Yes. It should be on Page 9. Go back to Page 9.

A Okay.

Q That is the same information, it just relates to April of 2005, is that right?

A That is correct. (Inaudible).

Q No, I don't. I haven't seen those.

A I'm not sure if you had a question about it.

Q All right. This is much shorter than the other one. Can you tell me why it's shorter?

A Again, basically what happened there is when we revised it we found that we were cutting and pasting the April of '06 into April of '05.

Q I see.

A And so that is pretty much what happened there.

Q That is the kind of thing I do all the time, and I apologize.

A I'm glad to hear it is not only us.

Q Go ahead.

A It's much shorter because of the plan that we were under at the time, if you recall, the mins and maxs and how far out we were permitted to hedge.

Q Were you actually hedging further than the --

MR. McWHIRTER: Jim, I'm going to be done in about another three or four questions. I don't want you to skip your flight. If you can hang on just a few more minutes.

A (By Ms. Wehle) And, basically, between the last April of '05 and July of '05 --

Q Uh-huh.

A -- what changed were the percentage hedge for a variety of the month as well as we added some length.

Q All right. Go to Page 15, the same four-month period, and that's October 2005?

A That's correct.

Q And what changes are there?

A Adding more contracts.

Q And in this instance the natural gas requirements as well as the hedge price increased further, is that correct?

A No, that is not necessarily correct.

Q Okay.

A Our percentage hedge has increased, our natural gas requirements didn't necessarily (inaudible).

Q The price did not increase?

A The price, and depending, again, on what we contracted for as far as additional hedges increased the price of the overall average hedge price, yes.

Q But you added more?

A That's correct.

goes based on (inaudible) and volume requirements. A risk management plan does not look at what price expectation is necessarily going to be out in the future. You know, if you do that, then you take a speculative approach to hedging, so you are always going to be trying to gauge the market, potentially game the market, and that is not what hedging is all about. Hedging is to layer in known volume (inaudible) over time to ensure that price volatility is mitigated.

Q So the essential ingredient of what you have done is to eliminate volatility irrespective of what's going on in the market prices or what is going on in your forecast?

A That's correct. Because if you take a different approach, John, what's going to happen is you are going to speculate every single time, is the price going to move up or is the price going to move down. And without a disciplined approach to it you are always going to -- you are really not hedging then, what you are doing is price speculating. And if you recall the order, that was something that was made very clear to the utilities is these are supposed to be nonspeculative programs. And just to be honest with you, when markets are rising our hedge programs look great, and in falling markets we don't look so smart.

Q And so overall --

A Overall, I think if you look at where we have been since the beginning of time, we are probably net/net on the

MR. McWHIRTER: Stop talking. That terminates my questions. Oh, I would like to have a late-filed exhibit. And Jim doesn't have to worry about this. For each month from February of 2005 through August of 2006, please provide the incremental hedge volumes and the average hedge price for those volumes for each delivery months. Why don't you just look at that.

MR. BEASLEY: Is that confidential, Joann?

MR. McWHIRTER: I think it will be.

WITNESS WEHLE: Yes, it will be.

MR. McWHIRTER: So mark it confidential.

(Confidential Late-filed Exhibit 11 marked for identification.)

MR. BEASLEY: We will read and sign the depositions.

(The deposition concluded at 4:20 p.m.)

111A

CERTIFICATE OF OATH

STATE OF Florida

COUNTY OF Hillsborough

I, the undersigned authority, certify that Carlos Aldazabal personally appeared before me at 702 N. Franklin St., Tampa 33602 and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Tampa, County of Hillsborough, State of Florida, this 18th day of October, 2006.

Notary Public State of Florida
Brenda Lee Irizarry
My Commission DD551587
Expires 07/29/2010

Brenda Irizarry
Notary Public
State of Florida

Personally known ✓ OR produced identification ________.

Type of identification produced ________________________.

111c

CERTIFICATE OF OATH

STATE OF Florida

COUNTY OF Hillsborough

I, the undersigned authority, certify that Joann Wehle personally appeared before me at 702 N. Franklin St, Tampa 33602 and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Tampa, County of Hillsborough, State of Florida, this 18th day of October, 2006.

Notary Public State of Florida
Brenda Lee Irizarry
My Commission DD551587
Expires 07/29/2010

Notary Public
State of Florida

Personally known ✓ OR produced identification ________.

Type of identification produced ____________________.

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2005

(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(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,338.0	0.0	1,338.0	2.010	2.010	26,900.00	26,900.00	
VARIOUS	JURISDIC.	SCH. - MB	25,085.0	0.0	25,085.0	3.205	5.826	803,900.00	1,461,500.00	573,100.00
TOTAL			26,423.0	0.0	26,423.0	3.144	5.633	830,800.00	1,488,400.00	573,100.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	454.6	0.0	454.6	3.520	3.520	16,000.01	16,000.01	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	841.9	0.0	841.9	3.581	3.581	30,146.53	30,146.53	
PROGRESS ENERGY FLORIDA		SCH. - MA	50.0	0.0	50.0	5.028	5.658	2,514.00	2,829.05	213.55
FLA. PWR. & LIGHT		SCH. - MA	570.0	0.0	570.0	4.057	4.660	23,122.54	26,564.27	2,284.63
CITY OF LAKELAND		SCH. - MA	175.0	0.0	175.0	2.949	4.801	5,161.10	8,401.68	2,885.33
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	3,375.0	0.0	3,375.0	2.049	5.249	69,168.20	177,163.91	105,013.71
THE ENERGY AUTHORITY		SCH. - MA	2,863.0	0.0	2,863.0	3.428	4.225	98,157.63	120,966.61	18,171.13
SOUTHERN COMPANY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	210.0	0.0	210.0	1.978	2.692	4,152.94	5,653.51	1,357.77
CAROLINA POWER & LIGHT		SCH. - MA	100.0	0.0	100.0	4.205	5.335	4,205.00	5,334.86	826.86
CARGILL ALLIANT		SCH. - MA	2,253.0	0.0	2,253.0	3.535	4.193	79,647.67	94,465.24	14,287.74
CITY OF TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF HOMESTEAD		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - MA	478.0	0.0	478.0	3.791	4.878	18,119.25	23,316.48	4,280.89
CALPEA		SCH. - MA	312.0	0.0	312.0	2.305	2.865	7,191.03	8,939.69	1,483.46
TEC WHOLESALE MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	(2,028.59)	(2,028.59)
HARDEE OTHERS*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		OATT	(2,370.0)	0.0	(2,370.0)	3.525	3.525	(83,550.14)	(83,550.14)	
ADJUSTMENTS TO PRIOR MONTHS:										
AUBURNDALE POWER PARTNERS	DECEMBER 2004	OATT	832.0	0.0	832.0	2.783	2.783	23,152.76	23,152.76	
AUBURNDALE POWER PARTNERS	DECEMBER 2004	OATT	(906.0)	0.0	(906.0)	3.094	3.094	(28,034.90)	(28,034.90)	
CITY OF LAKELAND	NOVEMBER 2004	SCH. - MA	(735.0)	0.0	(735.0)	3.673	4.802	(26,997.61)	(35,297.45)	(6,902.79)
CITY OF LAKELAND	NOVEMBER 2004	SCH. - MA	935.0	0.0	935.0	3.629	4.943	33,931.61	46,213.64	10,256.98
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			1,296.5	0.0	1,296.5	3.559	3.559	46,146.54	46,146.54	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			10,586.0	0.0	10,586.0	3.007	4.558	318,373.36	482,522.90	152,230.67
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			(2,444.0)	0.0	(2,444.0)	3.618	3.618	(88,432.28)	(88,432.28)	
TOTAL			9,438.5	0.0	9,438.5	2.925	4.664	276,087.62	440,237.16	152,230.67
CURRENT MONTH:										
$ DIFFERENCE			(16,984.5)	0.0	(16,984.5)	(0.219)	(0.969)	(554,712.38)	(1,048,162.84)	(420,869.33)
DIFFERENCE %			-64.3%	0.0%	-64.3%	-7.0%	-17.2%	-66.8%	-70.4%	-73.4%
PERIOD TO DATE:										
ACTUAL			9,438.5	0.0	9,438.5	2.925	4.664	276,087.62	440,237.16	152,230.67
ESTIMATED			26,423.0	0.0	26,423.0	3.144	5.633	830,800.00	1,488,400.00	573,100.00
DIFFERENCE			(16,984.5)	0.0	(16,984.5)	(0.219)	(0.969)	(554,712.38)	(1,048,162.84)	(420,869.33)
DIFFERENCE %			-64.3%	0.0%	-64.3%	-7.0%	-17.2%	-66.8%	-70.4%	-73.4%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JANUARY 2005.

EXHIBIT
1
10/18/06

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	**))))**	**DOCKET NO. 060001-EI FILED: October 10, 2006**

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 3-15)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 3 - 15) propounded and served on September 5, 2006, by the Florida Public Service Commission Staff.

EXHIBIT 3 10/18/06

11	Aldazabal	When it became clear that fuel expenses and the expense for purchased power were significantly more than had been projected in the September 2005 fuel filing, why did TECO not reproject fuel expenses for 2005 to include the additional fuel expense in the 2006 fuel factor?	9
12	Aldazabal	When responding to this question, refer to Order No. PSC 13694 and Order No. PSC-98-0691-FOF-PU. Why did TECO not advise the Commission that TECO had an under-recovery of over 10% in either 2005 or 2006 after the escalation of fuel prices caused by hurricanes Katrina and Rita?	10
13	Aldazabal	Provide an analysis of the factors that caused the under-recovery of $106,516,837 for the year 2005 with an approximate breakout of the contributing factors.	14
14	Aldazabal	When calculating the percent fuel cost under-recovery according to Order No. PSC 13694 and Order No. PSC-98-0691-FOF-PU for 2006, should the fuel expense under-recovery from 2005 be included with the current year fuel expense in consideration of the current percent under-recovery?	15
15	Aldazabal	When calculating the percent fuel cost under-recovery according to Order No. PSC 13694 and Order No. PSC-98-0691-FOF-PU for any specific period, how is the denominator in the percent calculation determined?	16

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TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
STAFF'S SECOND SET OF INTERROGATORIES
INTERROGATORY NO. 5

FILED: OCTOBER 10, 2006

5. For the wholesale sales listed for Schedule D sales on the Florida Public Service Commission A-6 Schedule, how is the total sales price for each sale determined?

A. Tampa Electric's 2006 monthly fuel Schedule A-6 shows two jurisdictional D sales and one separated D sale.

The total sales price for each jurisdictional D sale is calculated by taking Tampa Electric's hourly system incremental fuel expense adjusted for losses plus a [redacted] percent energy charge.

The total sales price for the separated schedule D sale is calculated by taking Tampa Electric's monthly system average fuel charge plus a non-fuel charge applicable to each megawatt-hour delivered to the delivery point during a calendar month.

7. For MA sales on the Florida Public Service Commission Schedule A-6, what costs for each sale are not included in columns 7 or 9, and how are these costs credited back to the general body of ratepayers, as directed by Order No. PSC 13694, issued September 20, 1984 in Docket No. 840001 which was amended by Order PSC-00-1744-PAA-EI issued May 19, 1998 in Docket No. 980269-PU.

A. As previously described in the company's response to interrogatory number 6, Tampa Electric computes the gain in column (9) of schedule A-6 as the difference between the total sales price on column (8) and the total for fuel adjustment on column (7) less the incremental O&M costs associated with making the sale. Therefore, the only costs associated with MA sales not included are the incremental O&M costs associated with making the sale. Those costs are credited against operating revenues in accordance with Order No. PSC-00-1744-PAA-EI, issued May 19, 1998 in Docket No. 980269-PU and amended in Order PSC-01-2371-FOF-EI, issued December 7, 2001, in Docket No. 010283-EI. As stated in Item 3, Part III of Order No. PSC-00-1744-PAA-EI and re-affirmed in Section C of Order No. PSC-01-2371-FOF-EI, the appropriate regulatory treatment for non-separated wholesale energy sales is as follows:

> "Each [investor-owned electric utility] shall credit its operating and maintenance revenues for an amount equal to the incremental operating and maintenance (O&M) cost of generating the energy for each such sale."

9. When responding to this question, refer to Order PSC-04-0999-FOF-EI in Docket 031033-EI. What are TECO's plans and timeline for implementing the order and the findings of the Hill and Associates study on coal transportation options prior to the next RFT for coal transportation?

A. Tampa Electric is developing plans to meet its long-term coal supply needs and transportation logistics. To develop the plan, Tampa Electric must understand the potential impact of numerous issues that are shaping the coal and electric utility industries. For example, the Clean Air Interstate Rule ("CAIR") is causing an estimated 70 GW of existing coal fired plants to add scrubbers and/or selective catalytic reduction units. This will allow many power plants to burn lower priced, higher sulfur coals such as the coal from the Illinois Basin that Tampa Electric has historically used. Additionally, the extreme price volatility of natural gas over the past five years has instigated a wave of proposed coal plants.

Recognizing this shift in coal supply and demand dynamics, Tampa Electric's fuel procurement strategy is to have a plan that provides optionality, flexibility, and reliability. Tampa Electric's objective is to have multiple coal suppliers from a variety of regions with multiple modes of delivery. To achieve this flexibility, optionality, and reliability Tampa Electric has proactively visited various coal suppliers, transporters (waterborne and rail), and terminals to help identify viable alternatives. The Company expects to apply this knowledge to an effective Request for Proposals ("RFP").

Tampa Electric has begun developing its strategy and process for coal procurement and transportation after the current coal transportation contract expires. This process is consistent with Order PSC-04-0999-FOF-EI and will attempt to capture the key recommendation of the Hill and Associates study to have multiple options for coal transportation to Tampa Electric's power plants. Through viable and cost-effective alternatives, Tampa Electric is working to increase the flexibility of its coal supply and transportation. This flexibility will position Tampa Electric to respond more quickly and effectively to the changing coal market dynamics.

11. When it became clear that fuel expenses and the expense for purchased power were significantly more than had been projected in the September 2005 fuel filing, why did TECO not reproject fuel expenses for 2005 to include the additional fuel expense in the 2006 fuel factor?

A. Tampa Electric filed a revised re-projection on October 14, 2005 when it became clear that its estimated fuel costs for July and August were less than actual fuel costs. However, Tampa Electric was not aware that fuel expenses and purchased power costs for September through December were higher than had been re-projected until after the October 14, 2005 revised re-projection filing. As previously stated, damage assessments caused by Hurricane Katrina were still being performed at the time of the company's October 14, 2005 filing. Once damage assessments to natural gas production facilities in the Gulf were better known, the fuel hearing had already occurred. Therefore, in light of the timing of events, the company did not reproject fuel expenses for 2005 to include the additional fuel expense in the 2006 fuel factor, which had already been approved.

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ORIGINAL

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COMMISSION CLERK

July 22, 2005

HAND DELIVERED

Mr. Todd Bohrmann
Division of Economic Regulation
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Ms. Adrienne Vining
Staff Counsel
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: FPSC Docket No. 050001-EI – Fuel and Purchased Power Cost Recovery Clause and Generation Performance Incentive Factor

Dear Mr. Bohrmann and Ms. Vining:

Commission Order No. 13694, issued in Docket No. 840001-EI on September 20, 1984 states:

> When a utility becomes aware that its projected fuel revenues . . . will result in an over- or under-recovery in excess of 10% of its projected fuel costs for the period, the utility shall so advise the Commission through a filing promptly made. . . .

Tampa Electric has now determined that its projected actual/estimated fuel and purchased power cost under-recovery for the current 2005 cost recovery period will be greater than the ten percent notification threshold set forth in Order No. 13694. Tampa Electric's current 2005 projected actual/estimated under-recovery is $99,909,938. This includes $31 million of the company's 2004 Actual True-up over-recovery reported in the company's March 1, 2005 filing.

Order No. 13694 further states:

> In light of certain timing considerations a utility may choose, in lieu of requesting a hearing, to inform the Commission, the Staff and the intervenors that a greater than ten percent over- or under-recovery is projected to occur.

CMP ____
COM ____
CTR ____
ECR ____
GCL ____
OPC ____
RCA ____
SCR ____
SGA ____
SEC 1
OTH ____

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

13. Provide an analysis of the factors that caused the under-recovery of $106,516,837 for the year 2005 with an approximate breakout of the contributing factors.

A. The chart below provides a breakout of the contributing factors behind the 2005 $106,516,837 under-recovery.

Tampa Electric's 2005 Under-Recovery
($000)

	Sept.	Oct.	Nov.	Dec.	Total
Variance Jurisdictional Revenues	2,016	(55)	(1,045)	(2,719)	(1,803)
Variance					
Fuel Cost	15,162	22,986	20,155	30,085	88,388
Purchased Power	18,801	13,126	(4,606)	(6,636)	20,684
Variance System Fuel & Purch. Power	33,963	36,111	15,548	23,449	109,072
Variance Jurisdictional Fuel & Purch. Power[(1)]	31,866	33,781	14,423	22,981	103,051
Variance Interest/Other	314	(316)	13	254	266
Total Under Recovery	**$(30,209)**	**$(63,957)**	**$(79,899)**	**$(106,517)**	

(1) Adjusted for jurisdictional separation and line losses.

15. When calculating the percent fuel cost under-recovery according to Order No. PSC 13694 and Order No. PSC-98-0691-FOF-PU for any specific period, how is the denominator in the percent calculation determined?

A. The under-recovery percentage is calculated by taking the actual fuel and purchased power costs in the current period plus the projected fuel and purchased power costs remaining in the period and then dividing that amount by the projected fuel and purchased power costs in the projection filing.

SCHEDULE A7
PAGE 1 OF 1

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2005

(1) PURCHASED FROM			(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(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		SCH. - J	186.0	0.0	101.0	85.0	11.765	11.765	10,000.00
HARDEE POWER PARTNERS		IPP	3,383.0	0.0	0.0	3,383.0	11.357	11.357	384,200.00
VARIOUS		OTHER	91,291.0	0.0	0.0	91,291.0	3.673	3.673	3,353,100.00
VARIOUS		MKT. BASE	12,364.0	0.0	0.0	12,364.0	4.914	4.914	607,600.00
TOTAL			107,224.0	0.0	101.0	107,123.0	4.065	4.065	4,354,900.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	4,828.0	0.0	0.0	4,828.0	12.983	12.983	626,807.83
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER & LIGHT		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CITY OF LAKELAND		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORLANDO UTIL. COMM.		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CAROLINA POWER & LIGHT		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
THE ENERGY AUTHORITY		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
REEDY CREEK		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
OKEELANTA		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CITY OF TALLAHASSEE		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CALPINE		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CONOCO		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CORAL POWER		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SEMINOLE ELEC. CO-OP		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
DUKE ENERGY		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
DYNEGY POWER MARKETING		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CITY OF HOMESTEAD		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SEMPRA ENERGY		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
COBB ELECTRIC MEMBERSHIP CORP		SCH. - JA	0.0	0.0	0.0	0.0	0.000	0.000	0.00
PROGRESS ENERGY FLORIDA		SCH. - D	91,460.0	0.0	0.0	91,460.0	3.933	3.933	3,596,810.20
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	DEC 2004	IPP	(15,485.0)	0.0	0.0	(15,485.0)	9.933	9.933	(1,538,082.62)
HARDEE PWR. PART.-NATIVE	DEC 2004	IPP	15,485.0	0.0	0.0	15,485.0	10.226	10.226	1,583,538.30
PROGRESS ENERGY FLORIDA	NOV 2004	SCH. - D	(70,384.0)	0.0	0.0	(70,384.0)	3.717	3.717	(2,616,001.47)
PROGRESS ENERGY FLORIDA	NOV 2004	SCH. - D	70,584.0	0.0	0.0	70,584.0	3.721	3.721	2,626,097.28
PROGRESS ENERGY FLORIDA	DEC 2004	SCH. - D	(79,545.0)	0.0	0.0	(79,545.0)	3.692	3.692	(2,936,775.15)
PROGRESS ENERGY FLORIDA	DEC 2004	SCH. - D	79,545.0	0.0	0.0	79,545.0	3.962	3.962	3,151,546.65
SUB-TOTAL OF ADJUSTMENTS	NOV. - DEC. 2004		200.0	0.0	0.0	200.0	135.161	135.161	270,322.99
TOTAL			96,488.0	0.0	0.0	96,488.0	4.658	4.658	4,493,941.02
CURRENT MONTH:									
DIFFERENCE			(10,736.0)	0.0	(101.0)	(10,635.0)	0.593	0.593	139,041.02
DIFFERENCE %			-10.0%	0.0%	-100.0%	-9.9%	14.6%	14.6%	3.2%
PERIOD TO DATE:									
ACTUAL			96,488.0	0.0	0.0	96,488.0	4.658	4.658	4,493,941.02
ESTIMATED			107,224.0	0.0	101.0	107,123.0	4.065	4.065	4,354,900.00
DIFFERENCE			(10,736.0)	0.0	(101.0)	(10,635.0)	0.593	0.593	139,041.02
DIFFERENCE %			-10.0%	0.0%	-100.0%	-9.9%	14.6%	14.6%	3.2%

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EXHIBIT 4
10/18/06

AUSLEY & MCMULLEN
ATTORNEYS AND COUNSELORS AT LAW
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TALLAHASSEE, FLORIDA 32301
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RECORDS AND REPORTING

ORIGINAL

May 2, 2000

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Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 000001-EI

Dear Ms. Bayo:

Enclosed for filing in the above proceeding are the original and ten (10) copies of Tampa Electric Company's Petition for a Mid-Course Correction to its Fuel and Purchased Power Cost Recovery Factors and Capacity Cost Recovery Clause Factors.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: All Parties of Record (w/enc.)

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EXHIBIT
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10/18/04

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FPSC-RECORDS/REPORTING

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3. Tampa Electric's current fuel and purchased power and capacity cost recovery factors were approved in Order No. PSC-99-2512-FOF-EI issued December 22, 1999, for application during the period January 2000 through December 2000. The new factors became effective with the first billing cycle for January 2000.

4. In Order No. 13694 issued in Docket No. 840001-EI on September 20, 1984, the Commission authorized each utility to seek a mid-course correction when it appeared that its projected fuel revenues will result in an over- or under-recovery in excess of ten percent.

5. Since the implementation of Tampa Electric's current factors, the company has monitored its fuel and purchased power and capacity cost recovery revenue and expenses on an ongoing basis. Based on actual results to date and updated estimates for the remainder of the year 2000, the company now projects that an under-recovery in excess of ten percent is likely to occur absent a mid-course correction to the company's current fuel and purchased power and capacity cost recovery factors.

<u>Fuel and Purchased Power Cost Recovery Factors</u>

6. Tampa Electric expects its fuel and purchased power total under-recovery through December 31, 2000 to be $37,581,200. This includes the September through December 1999 final true-up under-recovery of $8,662,661 as filed with this Commission on April 3, 2000 in Docket No. 000001-EI, and the January through December 2000 actual/reforecast under-recovery of $28,918,539. The total projected under-recovery of $37,581,200 is about 10 percent greater than Tampa Electric's forecasted jurisdictional system fuel expense for the period on which the current fuel and purchased power charges are based.

Docket No. 000001-EI. The January 2000 through December 2000 actual/reforecast is expected to result in an under-recovery of $11,663,509.

11. The total projected under-recovery of $11,758,452 is about 49 percent greater than Tampa Electric's forecasted jurisdictional system capacity expense for the period on which the current capacity charges are based.

12. Accordingly, Tampa Electric proposes a mid-course correction for capacity cost recovery factors similar to the fuel and purchased power cost recovery factors, effective with the first billing cycle in June 2000. The mid-course correction would be based on 50 percent of the $11,758,452 under-recovery, or $5,879,226, being recovered during June 2000 through December 2000. The remainder of the under-recovery would be recovered in the January 2001 through December 2001 period. This proposal would, based on current estimates, levelize the impact on overall rates over a longer period of time than simply the remaining seven months of 2000.

13. Tampa Electric attributes the under-recovery of its capacity costs to higher purchased power costs attributable to a tighter wholesale market.

14. Attached hereto as Exhibit "B" is a recalculation of Tampa Electric's capacity cost recovery factor which takes into account a currently projected under-recovery of $11,758,452 over the remainder of 2000, and a recalculation of the capacity cost recovery factors in a manner designed to recoup half of the under-recovery during the months June 2000 through December 2000. The other half of the under-recovery amount will be recovered during the period January 2001 through December 2001.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition to Modify Fuel and Purchased Power and Capacity Cost Recovery Factors to Effect a Mid-Course Correction, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 2nd day of May 2000 to the following:

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ATTORNEY

SCHEDULE E1-A
Mid-Course Correction

CALCULATION OF MID-COURSE CORRECTION
(PROJECTED PERIOD)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JUNE 2000 THRU DECEMBER 2000

1. ESTIMATED/ACTUAL OVER/(UNDER) RECOVERY January - December 2000	($28,918,539)
2. FINAL TRUE-UP OVER/(UNDER) RECOVERY January - December 1999	($8,662,661)
3. TOTAL OVER/(UNDER) RECOVERY	($37,581,200)
4. 50% OF TOTAL OVER/(UNDER) RECOVERY To be included in the 7 month projected period June thru December 2000	($18,790,600)
5. JURISDICTIONAL MWH SALES (Projected June thru December 2000)	10,295,591
6. TRUE-UP FACTOR (Lines 4/5) * (100 cents/1000 KWH)	**($0.183)**
7. REVENUE TAX FACTOR	1.00072
8. MID-COURSE CORRECTION FACTOR	**($0.183)**

SCHEDULE E-1E
Mid-Course Correction

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JUNE 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		2.486	1.0071	2.504
A1*	SL-2, OL-1&3		2.486	N/A	2.306
B	GSD,GSLD,SBF		2.486	1.0016	2.490
C	IS-1&3,SBI-1&3		2.486	0.9681	2.407
D	N/A		N/A	N/A	N/A
A	RST,GST	ON-PEAK	3.383	1.0071	3.407
		OFF-PEAK	2.097	1.0071	2.112
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	3.383	1.0016	3.388
		OFF-PEAK	2.097	1.0016	2.100
C	IST-1&3,SBIT-1&3	ON-PEAK	3.383	0.9681	3.275
		OFF-PEAK	2.097	0.9681	2.030
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.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
ACTUAL/PROJECTED FOR THE PERIOD: JAN. 2000 THRU DEC. 2000

C. TRUE-UP CALCULATION	JAN. 00 ACTUAL	FEB. 00 ACTUAL	MAR. 00 ACTUAL	APR. 00 PROJ.	MAY 00 PROJ.	JUNE 00 PROJ.	JULY 00 PROJ.	AUG. 00 PROJ.	SEPT. 00 PROJ.	OCT. 00 PROJ.	NOV. 00 PROJ.	DEC. 00 PROJ.	TOTAL
1. JURISDICTIONAL FUEL REVENUE	29,384,573	28,817,039	25,705,635	27,803,981	30,777,840	34,828,923	36,793,509	36,354,825	37,261,172	33,315,013	29,240,947	29,259,933	379,543,390
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
a. TRUE-UP PROVISION	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,574)	(305,569)	(3,666,883)
b. INCENTIVE PROVISION	23,059	23,059	23,059	23,059	23,059	23,059	23,059	23,059	23,059	23,059	23,059	23,053	276,702
c. OTHER ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
3. JURISDIC. FUEL REVENUE-THIS PERIOD	29,102,058	28,534,524	25,423,120	27,521,466	30,495,325	34,546,408	36,510,994	36,072,310	36,978,657	33,032,498	28,958,432	28,977,417	376,153,209
4. ADJ. TOTAL FUEL & NET PWR. TRANS.(A7)	30,307,479	25,383,208	27,020,835	28,410,733	36,861,063	41,120,343	44,683,370	45,855,541	40,061,294	33,653,760	27,898,610	28,776,447	410,032,683
5. JURISDIC. SALES - % TOTAL MWH SALES (B4)	0.9757439	0.9820880	0.9610349	0.9873260	0.9771041	0.9628529	0.9615732	0.9625761	0.9757312	0.9790268	0.9863671	0.9886907	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS. (LINE C4 X LINE C5)	29,572,333	24,928,544	25,967,965	28,050,655	36,017,096	39,592,842	42,966,331	44,139,448	39,089,054	32,947,933	27,518,271	28,451,006	399,241,478
a. 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	-
b. LINE 6 X LINE 6a	29,592,442	24,945,495	25,985,623	28,069,729	36,041,588	39,619,765	42,995,548	44,169,463	39,115,635	32,970,338	27,536,983	28,470,353	399,512,962
c. PEABODY COAL CONTRACT BUY-OUT AMORT.	375,966	373,435	370,904	368,373	365,842	363,311	360,780	358,249	355,718	353,187	350,656	348,125	4,344,546
d. PEABODY JURISD. (LINE 6c. X LINE 5)	366,847	366,746	356,452	363,704	357,466	349,815	346,916	344,842	347,085	345,780	345,876	344,188	4,235,717
e. FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0
f. JURISDIC. TOTAL FUEL & NET PWR.TRANS. INCL. PEABODY & FUEL CREDIT	29,959,289	25,312,241	26,342,075	28,433,433	36,399,054	39,969,580	43,342,464	44,514,305	39,462,720	33,316,118	27,882,859	28,814,541	403,748,679
7. TRUE-UP PROV. FOR MO. +/- COLLECTED	(857,231)	3,222,283	(918,955)	(911,967)	(5,903,729)	(5,423,172)	(6,831,470)	(8,441,995)	(2,484,063)	(283,620)	1,075,573	162,876	(27,595,470)
8. INTEREST PROVISION FOR THE MONTH	(59,876)	(53,988)	(48,381)	(50,283)	(62,218)	(87,042)	(114,104)	(148,204)	(172,504)	(178,232)	(175,835)	(172,405)	(1,323,070)
9. TRUE-UP & INT. PROV. BEG. OF MONTH (per Sch. E1-A - Line 3 less the deferred)	**************	**************	(17,347,141)	(18,008,903)	(18,665,579)	(24,325,952)	(29,530,592)	(36,170,592)	(44,455,217)	(46,806,210)	(46,962,488)	(45,757,176)	(369,060,341)
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD (T-Up filed Apr. 1999)	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936	7,879,936
10. TRUE-UP COLLECTED (REFUNDED)	305,574	305,574	305,574	305,574	305,574	305,574	305,574	305,574	305,574	305,574	305,574	305,569	3,666,883
11. END OF PERIOD TOTAL NET TRUE-UP	**************	(9,467,205)	(10,128,967)	(10,785,643)	(16,446,016)	(21,650,656)	(28,290,656)	(36,575,281)	(38,926,274)	(39,082,552)	(37,877,240)	(37,581,200)	

SCHEDULE A-2
MID-COURSE CORRECTION
TAMPA ELECTRIC COMPANY
DOCKET NO. 000001-EI
PAGE 5 OF 6

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) Jul-00	(h) Aug-00	(i) Sep-00	(j) Oct-00	(k) Nov-00	(l) Dec-00	TOTAL PERIOD	LINE NUMBER
		ESTIMATED													
1	FUEL COST OF SYSTEM NET GENERATION	28,107,340	25,441,708	27,216,137	27,016,433	30,697,488	32,967,477	36,096,853	35,013,336	32,288,290	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 *	2,606,104	2,276,124	2,679,944	2,786,044	2,950,884	2,959,944	3,307,064	3,076,764	3,225,624	2,730,084	2,373,824	2,501,064	33,374,468	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	766,600	861,500	643,200	974,800	960,600	868,400	854,500	734,600	659,500	9,226,300	3b
4	ENERGY COST OF ECONOMY PURCHASES	259,400	173,700	388,100	538,500	1,289,900	763,800	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)	27,920,836	25,191,984	27,155,793	27,914,289	34,534,104	36,850,633	40,169,889	40,237,672	35,739,866	31,626,950	26,674,706	28,097,867	382,114,589	5
6	JURISDICTIONAL KWH SOLD (MWH)	1,340,066	1,212,891	1,195,727	1,217,471	1,344,317	1,523,269	1,608,621	1,682,440	1,622,106	1,461,333	1,272,763	1,273,009	16,844,004	6
6a	JURISDICTIONAL % OF TOTAL SALES	0.9905877	0.9924467	0.9927412	0.9874143	0.9772118	0.9720682	0.9705846	0.9705774	0.9796190	0.9835312	0.9901111	0.9899851	-	6a
6b	JURISDIC. TOT. FUEL & NET PWR. TRANS. (LINE 5 X LINE 6a)	27,658,037	25,001,701	26,958,675	27,562,968	33,747,134	35,821,328	38,988,284	39,053,775	35,011,452	31,106,092	26,410,922	27,816,470	375,136,838	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	27,676,844	26,018,702	26,977,007	27,581,711	33,770,082	35,845,687	39,014,796	39,080,332	35,035,260	31,127,244	26,428,881	27,835,385	375,391,931	7a
7b	PEABODY COAL CONTRACT BUY-OUT AMORT.	375,966	373,435	370,904	368,373	365,842	363,311	360,780	358,249	355,718	353,187	350,656	348,125	4,344,546	7b
7c	PEABODY JURISDICTIONALIZED (LINE 7b x LINE 6a)	372,427	370,614	368,212	363,737	357,505	353,163	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)	28,049,271	25,389,316	27,345,219	27,945,448	34,127,587	36,198,850	39,364,964	39,428,040	35,383,728	31,474,614	26,776,069	28,180,024	379,663,130	8
9	COST PER KWH SOLD (cents/KWH)	2.0931	2.0933	2.2869	2.2954	2.5387	2.3764	2.4471	2.4916	2.1813	2.1687	2.1036	2.2137	2.2811	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)	2.1151	2.1153	2.3089	2.3174	2.5607	2.3984	2.4691	2.5136	2.2033	2.1907	2.1256	2.2357	2.3031	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 (¢/KWH) (EXCL. GPIF)	2.1166	2.1168	2.3106	2.3191	2.5626	2.4001	2.4709	2.5154	2.2049	2.1923	2.1273	2.2373	2.3048	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)	2.1149	2.1151	2.3089	2.3174	2.5608	2.3984	2.4692	2.5137	2.2032	2.1906	2.1256	2.2356	2.3031	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 cents/KWH	2.115	2.115	2.309	2.317	2.561	2.398	2.469	2.514	2.203	2.191	2.126	2.236	2.303	16

* INCLUDES ECONOMY SALES PROFITS (80%)
** BASED ON JURISDICTIONAL SALES ONLY

8

14656-99 Revised E2 & E6
12/1/99 for 2000

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	))))	DOCKET NO. 010001-EI Filed: February 9, 2001

PETITION OF TAMPA ELECTRIC COMPANY FOR A CORRECTION TO ITS FUEL AND PURCHASED POWER COST RECOVERY FACTORS

Tampa Electric Company ("Tampa Electric" or "company") hereby petitions the Commission for approval of the company's proposed modifications to its fuel and purchased power cost recovery factors to effect corrections, and in support thereof says:

1. Tampa Electric is an investor-owned electric utility subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes. Tampa Electric serves retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The company's principal offices are located at 702 North Franklin Street, Tampa, Florida 33602.

2. The persons to whom all notices and other documents should be sent in connection with this docket are:

Angela Llewellyn
Administrator, Regulatory Coordination
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601
(813) 228-1752
(813) 228-1770 (fax)

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Tallahassee, FL 32302
(850) 224-9115
(850) 222-7952 (fax)

2000 final true-up would be recovered in the January 2002 through December 2002 period. Based on current estimates, this proposal would levelize the impact on overall rates over a 21-month period of time rather than simply over the remaining nine months of 2001.

8. The projected under-recovery is primarily due to continued increases in natural gas and oil costs that have resulted in higher purchased power and generation costs. The increased purchased power costs are attributable to a tighter wholesale market and higher fuel costs. The increase in fuel costs is the result of unprecedented higher than projected oil and natural gas prices, due to extremely low oil and natural gas storage given the tightness of supply and demand.

9. Attached hereto as Exhibit "D" are revised and updated "E" Schedules which take into account the company's currently projected under-recovery of $86,335,390 over the remainder of 2001, and a recalculation of the fuel and purchased power cost recovery factors in a manner designed to recoup approximately half of the 2001 under-recovery during the months of April 2001 through December 2001. The remainder will be recovered over the period January 2002 through December 2002 period.

10. Attached hereto as Exhibit "E" is a comparison of an average residential bill reflecting the present fuel and purchased power cost recovery factors approved in Order No. PSC-00-2385-FOF-EI and the modified cost recovery factors proposed herein.

11. Because the proposed correction is based on an effective date beginning with the first billing cycle in April 2001 and the company wants to provide adequate notice to its customers, Tampa Electric asks that this petition be given expedited treatment and scheduled for consideration at the earliest Commission Agenda Conference possible. Such treatment is

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition for a Mid-Course Correction, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 9th day of February 2001 to the following:

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ATTORNEY

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DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
FILED: 2/9/01
EXHIBIT A
PAGE 1 OF 2

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL VERSUS REPROJECTION
FOR THE PERIOD:
JUNE 2000 THROUGH DECEMBER 2000

	JUN. 00 ACTUAL	JULY 00 ACTUAL	AUG. 00 ACTUAL	SEPT. 00 ACTUAL	OCT. 00 ACTUAL	NOV. 00	DEC. 00	TOTAL JUNE-DEC.
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	34,118,643	36,850,309	37,338,972	35,924,374	29,192,288	26,633,611	32,318,513	232,376,710
a. FUEL REL. R & D AND DEMO. COST	0	0	0	0	0	0	0	0
2. FUEL COST OF POWER SOLD *	3,906,288	4,359,568	3,392,194	3,399,270	3,622,495	2,796,157	3,030,027	24,505,999
3. FUEL COST OF PURCHASED POWER	10,179,913	13,522,470	19,144,629	18,641,829	13,821,491	11,766,765	11,708,495	98,785,593
a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0	0	0	0	0
b. PAYMENT TO QUALIFIED FACILITIES	830,371	1,077,356	1,112,828	858,654	1,012,426	602,485	762,489	6,256,609
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0	0	0	0	0
5. TOTAL FUEL & NET POWER TRANSACTION	41,222,639	47,090,567	54,204,235	52,025,587	40,403,710	36,206,705	41,759,470	312,912,913
6. ADJUSTMENTS TO FUEL COST (FT. MEADE / WAUCHULA WHEELING)	(4,172)	(6,530)	(4,484)	(4,283)	(3,460)	(3,168)	(3,748)	(29,865)
6a. ADJUSTMENTS TO FUEL COST	0	0	0	0	0	0	0	0
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	37,985,326	37,552,801	37,961,484	38,529,306	36,127,737	30,551,155	32,268,645	250,976,456
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0	0	0	0	0
a. TRUE-UP PROVISION	(2,684,371)	(2,684,371)	(2,684,371)	(2,684,371)	(2,684,371)	(2,684,371)	(2,684,371)	(18,790,597)
b. INCENTIVE PROVISION	23,059	23,059	23,059	23,059	23,059	23,059	23,053	161,407
c OTHER ADJUSTMENT	0	0	0	0	0	0	0	0
3. JURISDIC. FUEL REVENUE-THIS PERIOD	35,324,014	34,891,489	35,300,172	35,867,996	33,466,425	27,889,843	29,607,327	232,347,266
4. ADJ TOTAL FUEL & NET PWR. TRANS (A7)	41,218,467	47,084,037	54,199,751	52,021,304	40,400,230	36,203,537	41,755,722	312,883,048
5. JURISDIC. SALES - % TOTAL MWH SALES (B4)	0.9515591	0.9467675	0.9437046	0.9471879	0.9508597	0.9479122	0.9461973	
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS. (LINE C4 X LINE C5)	39,221,808	44,577,637	51,148,554	49,273,949	38,414,951	34,317,774	39,509,152	296,463,825
a. JURISDIC. LOSS MULTIPLIER	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	1.00068	
b. LINE 6 X LINE 6a	39,248,479	44,607,950	51,183,335	49,307,455	38,441,073	34,341,110	39,536,018	296,665,420
c. PEABODY COAL CONTRACT BUY-OUT AMORT.	363,311	360,780	358,249	355,718	353,187	350,656	348,125	2,490,026
d. PEABODY JURISD. (LINE 6c. X LINE 5)	345,712	341,575	338,081	336,932	335,831	332,391	329,395	2,359,917
e. FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0
j. JURISDIC. TOTAL FUEL & NET PWR.TRANS. INCL. PEABODY AND ALL ADJ.	39,594,191	44,949,525	51,521,416	49,644,387	38,776,904	34,673,501	39,865,413	299,025,337
7. TRUE-UP PROV. FOR MO. +/- COLLECTED	(4,270,177)	(10,058,036)	(16,221,244)	(13,776,391)	(5,310,479)	(6,783,658)	(10,258,086)	(66,678,071)
8. INTEREST PROVISION FOR THE MONTH	(94,266)	(118,678)	(176,012)	(242,580)	(281,000)	(304,603)	(338,257)	(1,554,396)
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(18,790,600)	(20,470,672)	(27,963,015)	(41,674,900)	(53,009,500)	(55,916,608)	(60,320,498)	(278,145,793)
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	2,381,673	2,381,673	2,381,673	2,381,673	2,381,673	2,381,673	2,381,673	16,671,711
10. (LINE 9 + LINE 9a) = PRIOR PERIOD TRUE-U	(16,408,927)	(18,088,999)	(25,581,342)	(39,293,227)	(50,627,827)	(53,534,935)	(57,938,825)	
11. TRUE-UP COLLECTED (REFUNDED)	2,684,371	2,684,371	2,684,371	2,684,371	2,684,371	2,684,371	2,684,371	18,790,597
12. END OF PERIOD TOTAL NET TRUE-UP	(18,088,999)	(25,581,342)	(39,293,227)	(50,627,827)	(53,534,935)	(57,938,825)	(65,850,797)	

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CALCULATION OF OVER/(UNDER)-RECOVERY
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JAN.,2001 THRU DEC.,2001
BASED ON REVISED ESTIMATES

	JAN. 01	FEB. 01	MAR. 01	APR. 01	MAY 01	JUNE 01	JULY 01	AUG. 01	SEPT. 01	OCT. 01	NOV. 01	DEC. 01	TOTAL
TRUE-UP CALCULATION													
1. JURISDICTIONAL FUEL REVENUE	34,406,228	31,072,628	30,474,059	31,208,530	33,848,629	39,346,670	41,058,438	40,744,664	41,844,872	37,468,009	32,226,797	32,127,868	425,847,392
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0	0	0	0	0	0	0	0	0	0
a. TRUE-UP PROVISION	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,566)	(5,487,571)	(65,850,797)
b. INCENTIVE PROVISION	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,870	1,150,407
c. OTHER ADJUSTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
3. JURISDIC. FUEL REVENUE-THIS PERIOD	29,014,529	25,680,929	25,082,360	25,816,831	28,456,930	33,954,971	35,666,739	35,352,965	36,453,173	32,096,310	26,835,098	26,736,167	361,147,002
4. ADJ. TOTAL FUEL & NET PWR. TRANS.	33,548,513	33,638,848	36,813,618	34,004,429	43,508,621	44,770,535	49,256,442	48,253,788	40,995,863	34,981,218	28,433,894	29,436,421	457,642,180
5. JURISDIC. SALES - % TOTAL MWH SALES	0.9515893	0.9513860	0.9537021	0.9660459	0.9655478	0.9486580	0.9488795	0.9483116	0.9650371	0.9634278	0.9642298	0.9629312	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS. (LINE 4 X LINE 5)	31,924,406	32,003,529	35,109,224	32,849,839	42,009,653	42,471,926	46,738,426	45,759,627	39,562,519	33,701,878	27,416,808	28,345,248	437,893,085
a. JURISDIC. LOSS MULTIPLIER	1.00067	1.00067	1.00067	1.00067	1.00067	1.00067	1 00067	1.00067	1.00067	1.00067	1.00067	1.00067	-
b. LINE 6 X LINE 6a	31,945,795	32,024,971	35,132,747	32,871,848	42,037,799	42,500,382	46,769,743	45,790,288	39,589,028	33,724,458	27,435,177	28,364,239	438,166,471
c. PEABODY COAL CONTRACT BUY-OUT AMORT.	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
d. PEABODY JURISD. (LINE 6c. X LINE 5)	328,864	326,385	324,766	326,525	323,913	315,846	313,518	310,931	313,972	311,010	308,828	305,975	3,810,533
e. FUEL CREDIT DIFFERENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0
f. JURISDIC. TOTAL FUEL & NET PWR.TRANS. INCL. PEABODY & FUEL CREDIT	32,274,659	32,351,356	35,457,513	33,198,373	42,361,712	42,816,228	47,083,261	46,101,217	39,902,998	34,035,468	27,744,005	28,670,214	441,997,004
7. TRUE-UP PROV. FOR MO. +/- COLLECTED	(3,260,130)	(6,670,427)	(10,375,153)	(7,381,542)	(13,904,782)	(8,861,257)	(11,416,522)	(10,748,252)	(3,449,825)	(1,939,158)	(908,907)	(1,934,047)	(80,850,002)
8. INTEREST PROVISION FOR THE MONTH	(356,054)	(360,305)	(379,252)	(400,269)	(431,291)	(466,594)	(495,152)	(529,134)	(541,079)	(528,513)	(508,787)	(488,938)	(5,485,368)
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(23,129,476)	(21,258,094)	(22,801,260)	(28,068,099)	(30,362,364)	(39,210,871)	(43,051,156)	(49,475,264)	(55,265,084)	(53,768,422)	(50,748,527)	(46,678,855)	(463,817,272)
9a. DEFERRED TRUE-UP BEGINNING OF PERIOD	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)	(42,721,321)
10. TRUE-UP COLLECTED (REFUNDED)	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,566	5,487,571	65,850,797
11. END OF PERIOD TOTAL NET TRUE-UP	(63,979,415)	(65,622,581)	(70,789,420)	(73,083,685)	(81,932,192)	(85,772,477)	(92,196,585)	(97,986,405)	(96,489,743)	(93,469,846)	(89,399,976)	(86,335,390)	

DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
FILED: 2/9/01
EXHIBIT B

DOCKET NO. 010001-EI
TAMPA ELECTRIC COMPANY
FILED: 2/9/01
EXHIBIT D

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SCHEDULE E1-A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2001 THRU DECEMBER 2001

1. ESTIMATED OVER/(UNDER)-RECOVERY (JANUARY - DECEMBER 2001) (EXHIBIT B LINE 11)	($86,335,390)
2. FINAL OVER/(UNDER) RECOVERY FOR JUNE - DECEMBER 2000 (EXHIBIT A PAGE 2 LINE 10)	(23,129,476)
3. OVER/(UNDER) RECOVERY FOR THE PERIOD JANUARY - DECEMBER 2001 (EXHIBIT C LINE C9)	(63,205,914)
4. APPROXIMATELY 50% OF ESTIMATED OVER/(UNDER)-RECOVER * TO BE COLLECTED IN THE APRIL - DECEMBER 2001 PERIOD	($30,838,165)
5. PROJECTED JURISDICTIONAL MWH SALES FOR THE 9 MONTH PERIOD (April - December 2001)	13,212,243
6. TRUE-UP FACTOR (Lines 4/5) * (100 cents/1000 KWH)	($0.2334)

* The remaining over/(under) recovery will be collected in the January - December 2002 period.

SCHEDULE E-1D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY
PROJECTION FOR THE PERIOD
APRIL 2001 THRU DECEMBER 2001

1. COST RATIO:

$$\frac{4.063 \text{ ON-PEAK}}{2.419 \text{ OFF-PEAK}} = 1.6796$$

2. SALES/GENERATION:

30.32 % ON-PEAK   69.68 % OFF-PEAK

3. FORMULA:

X = ON-PEAK   Y = OFF-PEAK

0.3032	*	1.6796	Y	+	0.6968	Y =	2.8199	INCLUDES TAX @ 1.00072
					1.2061	Y =	2.8199	
						Y =	2.3381	
						X =	1.6796	Y
						X =	1.6796	* 2.3381
						X =	3.9271	

	ON-PEAK	OFF-PEAK
4. FUEL COST (cents/KWH)	3.9271	2.3381
5. FUEL FACTOR (cents/KWH NEAREST .000)	**3.927**	**2.338**

SCHEDULE E1

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
FOR THE PERIOD OF: JANUARY 2001 THRU DECEMBER 2001

LINE NUMBER		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)		
		ESTIMATED													
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL PERIOD	LINE NUMBER
1	FUEL COST OF SYSTEM NET GENERATION	31,532,133	26,242,508	25,653,958	24,497,029	25,521,921	33,600,835	36,996,942	37,602,888	31,128,253	28,066,216	24,429,694	28,140,021	353,612,400	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 *	4,492,420	3,645,160	1,363,940	724,500	1,896,400	1,836,200	2,797,500	4,293,600	1,466,300	573,000	434,700	2,845,000	26,158,720	2
3	FUEL COST OF PURCHASED POWER	5,849,000	10,333,600	11,692,400	9,365,200	18,791,200	11,936,400	14,021,100	13,994,700	10,453,600	6,679,800	3,725,300	3,252,900	120,097,200	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	663,600	711,900	835,200	870,700	895,900	871,500	1,029,900	953,800	684,300	612,200	717,600	892,500	10,139,300	3b
4	ENERGY COST OF ECONOMY PURCHASES	0	0	0	0	0	0	0	0	0	0	0	0	0	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)	33,548,513	33,638,848	36,813,618	34,004,429	43,506,621	44,770,535	49,256,442	48,253,788	40,995,853	34,981,218	28,433,894	29,436,421	457,642,180	5
6	JURISDICTIONAL KWH SOLD (MWH)	1,378,418	1,245,214	1,221,392	1,250,560	1,355,714	1,575,444	1,843,668	1,631,022	1,675,234	1,501,455	1,291,527	1,287,620	17,057,268	6
6a	JURISDICTIONAL % OF TOTAL SALES	0.9515893	0.9513860	0 9537021	0.9660459	0.9655478	0 9486580	0.9488795	0.9483116	0.9650371	0 9634278	0 9642298	0 9629312	-	6a
6b	JURISDIC. TOT. FUEL & NET PWR. TRANS. (LINE 5 X LINE 6a)	31,924,406	32,003,529	35,109,224	32,849,639	42,009,653	42,471,926	46,738,428	45,759,627	39,562,519	33,701,678	27,416,808	28,345,248	437,893,085	6b
7	JURISDICTIONAL LOSS MULTIPLIER	1.00067	1.00067	1.00067	1 00067	1 00067	1 00067	1.00067	1 00067	1 00067	1.00067	1.00067	1 00067	-	7
7a	LINE 6b x LINE 7	31,945,795	32,024,971	35,132,747	32,871,648	42,037,799	42,500,382	46,769,743	45,790,286	39,589,026	33,724,458	27,435,177	28,364,239	438,186,471	7a
7b	PEABODY COAL CONTRACT BUY-OUT AMORT.	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091	7b
7c	PEABODY JURISDICTIONALIZED (LINE 7b x LINE 6a)	328,864	326,385	324,766	326,525	323,913	315,846	313,518	310,931	313,972	311,010	308,828	305,975	3,810,533	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)	32,274,659	32,351,356	35,457,513	33,198,373	42,361,712	42,816,228	47,083,261	46,101,217	39,902,998	34,035,468	27,744,005	28,670,214	441,997,004	8
9	COST PER KWH SOLD (cents/KWH)	2 3414	2.5981	2.9030	2.6547	3.1247	2.7177	2 8645	2 8265	2 3819	2 2668	2.1482	2 2266	2 5913	9
10	TRUE UP ** (cents/KWH)	0.2334	0.2334	0.2334	0.2334	0 2334	0 2334	0 2334	0 2334	0.2334	0 2334	0.2334	0.2334	0 2334	10
11	TOTAL (LINES 9+10)(cents/KWH)	2 5748	2.8315	3.1364	2.8881	3 3581	2 9511	3.0979	3 0599	2.6153	2.5002	2.3816	2 4600	2 8247	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 5767	2 8335	3.1387	2.8902	3.3605	2 9532	3 1001	3 0621	2 6172	2 5020	2 3833	2 4618	2 8267	13
14	GPIF ** (cents/KWH) (ALREADY ADJUSTED FOR TAXES)	(0.0067)	(0 0067)	(0.0067)	(0 0067)	(0 0067)	(0 0067)	(0 0067)	(0 0067)	(0.0067)	(0.0067)	(0 0067)	(0 0067)	(0 0067)	14
15	TOTAL RECOVERY FACTOR (LINES 13+14)	2 5700	2 8268	3.1320	2.8835	3 3538	2 9465	3 0934	3 0554	2.6105	2.4953	2.3766	2 4551	2 8200	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 cents/KWH	2.570	2.827	3.132	2.884	3.354	2.947	3.093	3.055	2.611	2 495	2.377	2.455	2.820	16

* INCLUDES ECONOMY SALES PROFITS (80%)
** BASED ON JURISDICTIONAL SALES ONLY

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ATTORNEYS AND COUNSELORS AT LAW
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TALLAHASSEE, FLORIDA 32301
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February 24, 2003

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor; FPSC Docket No. 030001-EI

Dear Ms. Bayo:

Enclosed for filing in the above docket are the original and ten (10) copies of a Petition of Tampa Electric Company for a Modification to its Fuel and Purchased Power Cost Recovery Factors.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: All Parties of Record (w/enc.)

EXHIBIT 9
10/17/06

DOCUMENT NUMBER-DATE
01866 FEB 24 8
FPSC-COMMISSION CLERK

3. Tampa Electric's current fuel and purchased power cost recovery factors ("fuel adjustment factors" or "factors") were approved in Order No. PSC-02-1761-FOF-EI issued December 13, 2002, for application during the period January 2003 through December 2003. The new factors became effective with the first billing cycle for January 2003.

4. In Order No. 13694 issued in Docket No. 840001-EI on September 20, 1984, the Commission authorized each utility to seek modifications to its fuel adjustment factors when it appears that its projected fuel revenues will result in an over- or under-recovery in excess of 10 percent.

5. Since the implementation of Tampa Electric's current factors, the company has monitored its fuel and purchased power cost recovery revenue and expenses on an ongoing basis. Based on updated estimates for 2003, the company now projects that an under-recovery in excess of 10 percent is likely to occur absent a modification to the company's current fuel adjustment factors.

6. Tampa Electric expects its total fuel and purchased power under-recovery December 2003 to be $89,272,063 as shown in Exhibit "A". This includes a projected current period under-recovery of $60,609,736, based on actual January 2003 and estimated reforecast February through December 2003 data as shown in Exhibit "B". The revised projected under-recovery for 2003 is 11 percent greater than Tampa Electric's forecasted jurisdictional system fuel costs for the period on which the current fuel adjustment factors are based.

7. Accordingly, Tampa Electric proposes modifications to its fuel adjustment factors, effective with the first billing cycle in April 2003. The company will collect the $60,609,736 estimated reforecast under-recovery during the remaining nine months of 2003.

12. The above-listed market and operational factors have contributed to the company's projected fuel and purchased power cost under-recovery exceeding the 10 percent variance threshold established by the Commission.

13. Attached hereto as Exhibit "C" are revised and updated "E" Schedules which take into account the company's currently projected under-recovery of $60,609,736 over the remainder of 2003, and a recalculation of the fuel adjustment factors in a manner designed to recoup the under-recovery during the months of April 2003 through December 2003.

14. Attached hereto as Exhibit "D" is a comparison of an average residential bill reflecting the present fuel adjustment factors approved in Order No. PSC-02-1761-FOF-EI and the modified factors proposed herein.

15. Because the proposed fuel adjustment factor modifications are based on an effective date beginning with the first billing cycle in April 2003 and the company wants to provide adequate notice to its customers, Tampa Electric asks that this petition be given expedited treatment and scheduled for consideration at the March 4, 2003 Commission Agenda Conference. Such treatment is warranted to effect the goal in Order No. 13694 of levelizing cost recovery factors and mitigating rate shock that customers experience when factors are adjusted, by spreading the increase over as long a period of time as is practicable.

WHEREFORE, Tampa Electric urges the Commission to approve the company's proposed modifications to its fuel and purchased power cost recovery factors as set forth in the schedules attached hereto, for application on customer bills beginning with the first billing cycle in April 2003 and thereafter until modified by subsequent Commission order. To achieve the

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition for a Modification to Fuel and Purchased Power Cost Recovery Factors, filed on behalf of Tampa Electric Company, has been furnished by U. S. Mail or hand delivery (*) on this 24th day of February 2003 to the following:

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ATTORNEY

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

DOCKET NO 030001-EI
TAMPA ELECTRIC COMPANY
FILED 02/24/03
EXHIBIT 6

			ACTUAL												
			Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	TOTAL
A	1	Fuel Cost of System Net Generation	31,877,915	25,335,491	33,837,562	41,680 745	41,847,866	45 045,564	51,707,470	52 106,110	36,134,631	37,844,665	42 140 517	46,871,932	486,210 686
	2	Fuel Cost of Power Sold [1]	468,396	360,800	1,530,300	3,699,800	668,100	1 388,600	2,269,900	2 541,800	200,200	296 200	2 676 200	3,282,900	19,371 996
	3	Fuel Cost of Purchased Power	14,320,140	7,386,800	5,896,100	3,568,000	10,705,300	10,666,300	12 332,100	11,915,800	28,278,100	17,102,800	3 383 500	4 679,300	128,418 040
	3a	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
	3b	Payments to Qualifying Facilities	1,258,765	846,900	1,023,900	1,072,300	1,128,300	1,085,200	1,151,800	1,156 700	1,092 700	1,122,400	1,009 100	1,035,200	12,984,665
	4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	Adj to Fuel Cost (Ft Meade/Wauchula Wheeling)	(6,108)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6 000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(72,108)
	5a	Adj to Fuel Cost	(2,738)	0	0	0	0	0	0	0	0	0	0	0	(2,738)
	5b	Adj. To Fuel Cost (Incremental Hedging O&M)	0	34,583	34,583	34,583	34,583	34,583	34 583	34,583	34,583	34,583	34,583	69,170	415 000
	6	TOTAL FUEL & NET POWER TRANS	46,969,578	33,216,474	39,255,545	42,830,026	53,043,949	56,438,047	62,950,953	62,667,393	63,334,014	55,802,466	43,885,500	51,366,702	610,579,751
[1]		Includes Gains													
B	1	Jurisdictional MWH Sales	1,479,489	1,316,527	1,265,933	1,327,162	1,405,680	1,642,939	1,724,460	1,704,885	1,749,820	1,824,913	1,394,208	1,422 679	18,060 814
	2	Non-Jurisdictional MWH Sales	46,230	18,904	30,550	41,377	46,115	54,526	54,542	54,891	41,155	36,346	22 961	23 114	468 791
	3.	TOTAL SALES (LINE B1+B2)	1,525,719	1,335,511	1,296,483	1,368,539	1,451,695	1,697,465	1,779,002	1,759,776	1,790,975	1,861,259	1,417,169	1,445,993	18,529,605
	4.	Jurisdictional % of Total Sales	0.9696995	0 9872028	0 9764382	0 9697660	0 9682337	0 9678780	0 9693412	0 9688080	0 9770208	0 9781214	0 9837980	0 9840151	.
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	43,921,774	39,526,541	37,939,683	39,777,360	42,144,658	49,290,611	51 741,746	51,154,169	52,503,196	48,741,906	41,795 907	42,656,286	541,195 737
	1a	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	True-up Provision	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263,799)	(263 799)	(263 802)	(3,165 591)
	2a	Incentive Provision	69,203	69,203	69,203	69,203	69,203	69,203	69,203	69,203	69,203	69,203	69 203	69,198	830 431
	2b	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
	3.	FUEL REVENUE APPLICABLE TO PERIOD	43,727,178	39,331,945	37,745,087	39,582,764	41,950,060	49,095,015	51,547,150	50,959,573	52,308,602	48,547,310	41,601,311	42,463,682	538,860,577
	4	Total Fuel and Net Power Transactions (Line A6)	46,969,578	33,216,474	39,255,545	42,830,026	53,043,949	56,438,047	62,950,053	62,667,393	63,334,014	55,802 466	43,665,500	51,366,702	610 579 751
	5	Jurisd Total Fuel and Net Power Transactions (Line A6*Line B4)	45,545,770	32,794,053	38,330,535	41,341,152	51,358,939	53,657,296	61,020,060	60,712,872	61,878,655	54,581,568	43 174,467	50 545 610	594,960,767
	5a	Jurisdictional Loss Multiplier	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	1 00114	.
	5b	Jurisdictional Sales Adjusted for Line Losses	45,617,715	32 831,438	38,374,232	41,388 281	51,417,486	53 718,435	61,089,643	60 781,864	61,949,197	54,643 811	43,223,606	50,603 232	595 639,042
	5c	Peabody Coal Contract Buyout Amortization	284,852	282,321	279,790	277,259	274,728	272,197	269,666	267,135	264,604	262,073	259,542	257 011	3 281 178
	5d	Peabody Jurisdictionalized (Line 5c*Line B4)	276,221	278,731	273,197	268,876	266,001	263,453	261,396	258,803	258,524	256,339	255,337	252 903	3 169 783
	6	JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY	45,893,936	33,110,169	38,647,429	41,657,157	51,683,489	53,981,888	61,351,041	61,040,667	62,207,721	54,900,150	43,479,023	50,856 135	598,808 825
	7	Over/(Under) Recovery	(2,166,758)	6,221,776	(902,342)	(2,074,393)	(9,733,429)	(4 886,973)	(9,803,891)	(10 081,114)	(9,899,119)	(6,352 840)	(1,677,712)	(8,392 453)	(59 948,248)
	8	Interest Provision	(35,074)	(32,880)	(29,843)	(31,196)	(37,323)	(44 973)	(52 869)	(63,179)	(73 751)	(82 322)	(86,571)	(91 925)	(661 488)
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD													(60,609,736)

2 208

SCHEDULE E1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: APRIL 2003 THROUGH DECEMBER 2003

	DOLLARS	MWH	CENTS/KWH
1. Fuel Cost of System Net Generation (E3)	458,767,929	17,390,363	2 63806
2. Nuclear Fuel Disposal Cost	0	0	0 00000
3. Coal Car Investment	0	0	0 00000
4a. Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(72,000)	17,390,363 (1)	(0 00041)
4b. Adjustments to Fuel Cost (Incremental Hedging O&M)	415,000	17,390,363 (1)	0 00239
5. TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)	459,110,929	17,390,363	2.64003
6. Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	80,945,700	1,628,683	4 97001
7. Energy Cost of Economy Purchases (E9)	0	0	0 00000
8. Demand and Non-Fuel Cost of Purchased Power	0	0	0 00000
9. Energy Payments to Qualifying Facilities (E8)	12,329,300	460,855	2 67531
10. TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)	93,275,000	2,089,538	4.46391
11. TOTAL AVAILABLE KWH (LINE 5 + LINE 10)		19,479,901	
12. Fuel Cost of Schedule D Sales - Jurisd. (E6)	746,100	32,326	2.30805
13. Fuel Cost of Schedule D HPP Sales - Separated (E6)	0	0	0 00000
14. Fuel Cost of Market Based Sales - Jurisd. (E6)	3,431,800	69,773	4 91852
15. TOTAL FUEL COST AND GAINS OF POWER SALES	4,177,900	102,099	4.09201
16. Net Inadvertant Interchange		0	
17. Wheeling Received Less Wheeling Delivered		0	
18. Interchange and Wheeling Losses		1,400	
19. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)	548,208,029	19,376,402	2.82926
20. Net Unbilled	NA (1)(a)	NA (a)	NA
21. Company Use	1,358,045 (1)	48,000	0.00735
22. T & D Losses	24,074,120 (1)	850,898	0 13029
23. System MWH Sales	548,208,029	18,477,504	2 96689
24. Wholesale MWH Sales	(13,527,425)	(448,870)	3 01366
25. Jurisdictional MWH Sales	534,680,604	18,028,634	2 96573
26. Jurisdictional Loss Multiplier			1 00114
27. Jurisdictional MWH Sales Adjusted for Line Loss	535,288,138	18,028,634	2.96910
28. True-up (2) (PER SCHEDULE E1-C LINE 3B FILED 9/20/02)	3,165,591	18,028,634	0.01756
28a True-up (2) (PER SCHEDULE E1-A LINE 5)	60,609,736	13,996,865	0.43302
29 Peabody Coal Contract Buy-Out Amort. (Jurisdictionalized)	3,173,323	18,028,634	0 01760
30 Total Jurisdictional Fuel Cost (Excl. GPIF)	602,236,788		3 43728
31. Revenue Tax Factor			1 00072
32. Fuel Factor (Excl. GPIF) Adjusted for Taxes	602,670,398	18,028,634	3 43975
33. GPIF Adjusted for Taxes (2)	(831,029)	18,028,634	(0 00461)
34. Fuel Factor Adjusted for Taxes Including GPIF	601,839,369	18,028,634	3.43514
35. Fuel Factor Rounded to Nearest .001 cents per KWH			3.435

INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: APRIL 2003 THROUGH DECEMBER 2003

1.	TOTAL AMOUNT OF ADJUSTMENTS		
A.	GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY) *(January 2003 Through December 2003)*	*($831,029)*	
B.	TRUE-UP OVER / (UNDER) RECOVERED (January 2003 Through December 2003)	($60,609,736)	
2.	TOTAL SALES (April 2003 Through December 2003)	13,996,865	MWh
3.	ADJUSTMENT FACTORS		
A.	GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0046)**	Cents/kWh
B.	TRUE-UP FACTOR	**0.4330**	Cents/kWh

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: APRIL 2003 THRU DECEMBER 2003

SCHEDULE E1-E

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS,GS,TS	3.435	1.0043	3.450
A1*	SL-2, OL-1&3	3.435	N/A	3.177
B	GSD,GSLD,SBF	3.435	1.0005	3.437
C	IS-1&3,SBI-1&3	3.435	0.9745	3.347
A	RST,GST			
	ON-PEAK	4.366	1.0043	4.385
	OFF-PEAK	2.951	1.0043	2.964
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	4.366	1.0005	4.368
	OFF-PEAK	2.951	1.0005	2.952
C	IST-1&3, SBIT-1&3			
	ON-PEAK	4.366	0.9745	4.255
	OFF-PEAK	2.951	0.9745	2.876

* GROUP A1 IS BASED ON GROUP A, 15% ON-PEAK AND 85% OFF-PEAK

Table #1

Over Recovery Calculations, 2005 and 2006
Tampa Electric Company

		Jurisdictional Fuel Revenue			True-up Provision	Incentive Provision	Jurisdictional Fuel Revenue Applicable To Period	Total Fuel and Net Power Transactions	Jurisdictional Loss Multiplier	Jurisdictional Total Fuel and Net Power Transactions	Waterborne Transportation Disallowance	True-up Provision for Month Over/Under Collection	
		Dollars	MWH	c/kWh								Calculated	Reported
		2007 ~~2006~~ (d) * (e)								[(i) * (j)]			
Year (a)	Month (b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
2005	12												
2006	1	78,892,520	1,469,651	5.368112566	(12,304,685)	(60,795)	66,527,040	58,030,624	1.000860	58,080,530	(1,071,311)	9,517,821	9,517,821
2006	2	71,463,740	1,330,154	5.372591444	(12,304,685)	(60,795)	59,098,260	62,061,788	1.000860	62,115,161	(859,769)	(2,157,132)	(2,157,132)
2006	3	70,849,707	1,321,386	5.361772185	(12,304,685)	(60,795)	58,484,227	58,561,730	1.000860	58,612,093	(1,325,503)	1,197,637	1,197,637
2006	4	75,032,639	1,397,929	5.367414153	(12,304,685)	(60,795)	62,667,159	72,362,989	1.000860	72,425,221	(2,071,141)	(7,686,921)	(7,686,921)
2006	5	85,084,903	1,581,413	5.380308812	(12,304,685)	(60,795)	72,719,423	90,153,144	1.000860	90,230,676	(1,965,800)	(15,545,453)	(15,545,453)
2006	6	94,864,023	1,761,693	5.384821476	(12,304,685)	(60,795)	82,498,543	89,424,737	1.000860	89,501,642	(1,090,636)	(5,912,463)	(5,912,463)
2006	7	103,171,716	1,906,509	5.411551480	(12,304,685)	(60,795)	90,806,236	94,815,192	1.000860	94,896,733	(1,276,282)	(2,814,215)	(2,814,215)
2006	8	103,189,703	1,906,858	5.411504318	(12,304,685)	(60,795)	90,824,223	98,814,235	1.000860	98,899,215	(1,276,282)	(6,798,710)	(6,798,710)
2006	9	104,337,877	1,927,975	5.411785786	(12,304,685)	(60,795)	91,972,397	88,962,576	1.000860	89,039,083	(1,276,282)	4,209,596	4,209,596
2006	10	93,633,584	1,730,884	5.409581694	(12,304,685)	(60,795)	81,268,104	81,338,949	1.000860	81,408,900	(1,276,282)	1,135,486	1,135,486
2006	11	80,833,800	1,494,828	5.407565285	(12,304,685)	(60,795)	68,468,320	71,687,141	1.000860	71,748,792	(1,276,282)	(2,004,190)	(2,004,190)
2006	12	80,046,367	1,480,405	5.407058677	(12,304,687)	(60,789)	67,680,891	83,123,703	1.000860	83,195,189	(1,276,282)	(14,238,016)	(14,238,016)
2007	1	92,120,126	1,563,258	5.892829359	(13,148,082)	8,316	78,980,360	74,985,154	1.000870	75,050,744	(1,276,282)	5,205,898	--
2007	2	84,231,631	1,429,392	5.892829359	(13,148,082)	8,316	71,091,865	73,562,209	1.000870	73,626,554	(1,276,282)	(1,258,407)	--
2007	3	82,680,698	1,403,073	5.892829359	(13,148,082)	8,316	69,540,932	78,794,915	1.000870	78,863,837	(1,276,282)	(8,046,623)	--
2007	4	85,349,678	1,448,365	5.892829359	(13,148,082)	8,316	72,209,912	74,983,966	1.000870	75,049,555	(1,276,282)	(1,563,361)	--
2007	5	94,002,650	1,595,204	5.892829359	(13,148,082)	8,316	80,862,884	94,023,905	1.000870	94,106,148	(1,276,282)	(11,966,982)	--
2007	6	109,412,752	1,856,710	5.892829359	(13,148,082)	8,316	96,272,986	95,791,436	1.000870	95,875,225	(1,276,282)	1,674,043	--
2007	7	114,463,673	1,942,423	5.892829359	(13,148,082)	8,316	101,323,907	107,984,838	1.000870	108,079,293	(1,276,282)	(5,479,104)	--
2007	8	114,569,331	1,944,216	5.892829359	(13,148,082)	8,316	101,429,565	108,532,469	1.000870	108,627,403	(1,276,282)	(5,921,556)	--
2007	9	116,459,810	1,976,297	5.892829359	(13,148,082)	8,316	103,320,044	95,823,571	1.000870	95,907,388	(1,276,282)	8,688,938	--
2007	10	104,559,536	1,774,352	5.892829359	(13,148,082)	8,316	91,419,770	80,227,480	1.000870	80,297,655	(1,276,282)	12,398,397	--
2007	11	89,865,000	1,524,989	5.892829359	(13,148,082)	8,316	76,725,234	67,718,685	1.000870	67,777,919	(1,276,282)	10,223,597	--
2007	12	89,100,464	1,512,015	5.892829359	(13,148,082)	8,316	75,960,698	81,120,864	1.000870	81,191,821	(1,276,278)	(3,954,845)	--
2006 Total		1,041,400,579	19,309,685		(147,656,222)	(729,534)	893,014,823	949,336,807		950,153,235	(16,041,852)	(41,096,560)	(41,096,560)
2007 Total		1,176,815,348	19,970,294		(157,776,984)	99,792	1,019,138,156	1,033,549,492		1,034,453,542	(15,315,380)	(6)	

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EXHIBIT 9
10/18/06

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 3
Company/ FPSC Staff
Witness: Conf. Staff Exhibit - 2
Date: 11-06-08/06

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 4
Company/ FPL
Witness: G. Yupp (GJY-4)
Date: 11/06-08/06

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power & Light Company to recover costs of natural gas storage project.	DOCKET NO. ________ FILED: April 28, 2006

PETITION OF FLORIDA POWER & LIGHT COMPANY TO RECOVER NATURAL GAS STORAGE PROJECT COSTS THROUGH THE FUEL COST RECOVERY CLAUSE

Florida Power & Light Company ("FPL" or the "Company"), pursuant to Section 366.06, Florida Statutes and prior orders of the Commission, hereby petitions for an order approving recovery, through the Fuel and Purchase Power Cost Recovery Clause (the "Fuel Clause"), of the costs of its participation in the subsurface natural gas storage facility, MoBay Gas Storage Hub, in Mobile County, Alabama (the "Gas Storage Facility") that is to be built and operated by Falcon Gas Storage, Inc. ("MoBay"; FPL's participation in the Gas Storage Facility will be referred to as the "Gas Storage Project"). As further discussed below and in the affidavit submitted with this Petition, the Gas Storage Project will substantially increase FPL's ability to hedge the physical supply of natural gas, resulting in a significant increase in system reliability and a reduction in natural gas price volatility. The location of the Gas Storage Facility at the termini of the Gulfstream Natural Gas Systems ("Gulfstream") and the Florida Gas Transmission ("FGT") Zone 3, Mobile Bay pipelines will also allow FPL to realize the maximum benefit of its existing firm transportation arrangements and avoid "pancaked" pipeline transportation fees. FPL currently recovers the costs of natural gas storage arrangements through the Fuel Clause, as part of its gas transportation charges. Recovery of reasonably and prudently incurred costs for the Gas Storage Project through the Fuel Clause is appropriate. In further support of this Petition, FPL states:

Background

1. FPL is a public utility subject to the regulatory jurisdiction of the Commission under Chapter 366, Florida Statutes. The Company's principal offices are located at 700 Universe Boulevard, Juno Beach, Florida.

2. All notices, pleadings and other communications required to be served on the petitioner should be directed to:

John T. Butler, Esq.
Senior Attorney
Florida Power & Light Company
9250 W. Flagler Street
Miami, Florida 33174
(305) 552-3867
(305) 552-3865 (Fax)

-and-

Mr. William G. Walker, III
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859
(850) 521-3910
(850) 521-3939 (Fax)

3. The justification for approval of the Gas Storage Project is addressed in the affidavit of Gerard J. Yupp, which is attached as Exhibit A and made part of this Petition.

Background on Natural Gas Storage

4. FPL depends upon natural gas for a substantial portion of the electric energy it generates each year. For example, slightly over 50% of FPL's 2005 total generated MWh were produced with natural gas. Unlike coal, oil and nuclear fuel, it is impractical to store significant quantities of natural gas at the generating facilities where it is burned. This means that, in the absence of off-site storage arrangements, FPL must depend on a constant supply of natural gas into the pipelines that deliver it to FPL. Any disruptions of those sources of supply by hurricanes

or other events can result in nearly immediate and quite substantial reductions in the amount of natural gas available for FPL's gas-fired generating facilities.

5. FPL has utilized small-scale natural gas storage arrangements for several years. Since 2003, FPL has recovered costs associated with those arrangements through the Fuel Clause as part of its natural gas transportation charges. Additionally, FPL has included the results of its physical hedging activities associated with natural gas storage in the Fuel Clause and in its Hedging Report filed each April.

Description of Gas Storage Project and Its Benefits

6. As explained in greater detail in Mr. Yupp's affidavit, the Gas Storage Facility is located in Mobile County, Alabama. It will entail the high pressure injection of natural gas underground into an existing, depleted oil field. The Gas Storage Facility is situated at the input termini of the Gulfstream pipeline and FGT Mobile Bay pipelines. FPL's utilization of natural gas storage over the past several years has been beneficial in enhancing the reliability of natural gas supply and mitigating some of the impact of natural gas price volatility, particularly during severe weather events. However, the 2004 and 2005 hurricane seasons presented numerous fuel supply challenges that have caused FPL to re-evaluate the extent of natural gas storage from which FPL and its customers could benefit.

7. The susceptibility of the Destin/Mobile Bay area to production shut-ins due to the threat or impact of severe weather events has proven to be a particularly significant challenge. Price volatility in the Destin/Mobile Bay area is high due to this supply limitation. Approximately 48% of the firm gas transportation capacity, on both FGT and Gulfstream, which FPL uses to supply its gas-fired generating facilities, is tied to off-shore production in the Destin/Mobile Bay area. Production shut-ins throughout this area have a significant impact on the availability of natural gas to supply both the FGT and Gulfstream pipelines. To the extent that production is curtailed in the area, FPL must find alternate means to supply gas into the FGT

and Gulfstream pipelines. FPL's existing small-scale natural gas storage arrangement is tied only to FGT and cannot provide storage for the Gulfstream pipeline. Therefore, FPL's options for obtaining natural gas supply for Gulfstream after production shut-ins are currently very limited.

8. The Gas Storage Project is a critical step in helping reduce FPL's vulnerability to natural gas supply curtailments in the Destin/Mobile Bay area and limiting FPL's exposure to the volatility inherent in relying on spot market gas or alternate fuels during severe weather events and periods of high demand. Natural gas storage also allows FPL to better manage and respond to intra-day changes in its natural gas requirements due to load variance, unit outages, etc. The ability to withdraw gas from storage on an intra-day basis allows FPL to potentially avoid having to purchase higher priced, intra-day natural gas and/or dispatching generation with alternate fuels. The Gas Storage Project will enhance FPL's ability to manage day-to-day and intra-day changes. Natural gas that is withdrawn from the Gas Storage Facility may be fed directly into the Gulfstream and/or FGT pipelines and transported to FPL's generating facilities using FPL's current firm transportation agreements. Because the withdrawn natural gas does not first have to be transported through other pipelines, FPL will not be subjected to multiple or "pancaked" transportation charges.

9. FPL will be an "anchor tenant" of the Gas Storage Facility. Its entitlement to store up to 6 million dekatherms which represents approximately 50% of the Gas Storage Facility's Phase I capacity. Six million dekatherms corresponds to approximately five days of FPL's typical natural gas consumption. Thus, the Gas Storage Project will substantially improve FPL's ability to withstand disruptions to the Gulf of Mexico production facilities, such as occurred in the 2005 hurricane season, without having to reduce the output of its gas-fired generating facilities. Moreover, as explained in Mr. Yupp's affidavit, the ability to store a substantial volume of natural gas allows FPL to be more selective as to when it purchases gas.

Timing of the Gas Storage Project

10. In order to secure a substantial participation in the Gas Storage Facility and to help ensure the facility's financial viability, FPL entered into a Firm Storage Service Precedent Agreement (the "Precedent Agreement") with MoBay on April 1, 2006. The Gas Storage Facility is scheduled to go into service between December 31, 2007 and July 1, 2008. FPL is entitled under the Precedent Agreement to terminate its involvement anytime after December 31, 2007 if the Gas Storage Facility is not yet in service and MoBay is not exercising commercially reasonable efforts to complete it. A copy of the Precedent Agreement is Attachment 2 to Mr. Yupp's affidavit.

Proposed Cost Recovery for Gas Storage Project

11. The Gas Storage Project will provide substantial additional supply-reliability and volatility-reduction benefits to FPL and its customers. As such, it is a form of expanded, non-speculative physical hedging. In approving the Hedging Resolution in Order No. PSC-02-1484-FOF-EI, Docket No. 011605-EI, dated October 30, 2002 (the "Hedging Order"), the Commission stated:

> In addition, [the Hedging Resolution] maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Further, the [Hedging Resolution] appears to remove disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs."

FPL believes that recovery of the costs for the Gas Storage Project through the Fuel Clause is appropriate and consistent with the intent of the Hedging Resolution as described in the Hedging Order.

12. As presently contemplated, the Gas Storage Project will entail the following financial responsibilities for FPL:

a. A monthly storage reservation charge.

b. In order to maintain sufficient pressure in the Gas Storage Facility to permit natural gas withdrawals as needed, FPL will either have to provide or lease from MoBay an amount of gas equal to 50% of its MSQ (this is referred to as "Base Gas" and would amount to 3 million dekatherms for FPL). Based on MoBay's pricing information, FPL expects that providing its own Base Gas will be less expensive than leasing it from MoBay for the term of the agreement.

c. Fuel retention and commodity charges for injections and withdrawals of natural gas.

d. A monthly inventory insurance charge applied to the total of a tenant's MSQ and Base Gas. This insurance protects against the risk of fire, sabotage and other risks that could result in losing all or part of the volume of the stored gas (for which tenants retain the risk of loss). FPL has the option to obtain this insurance itself rather than paying the monthly inventory insurance charge if deemed beneficial to FPL's customers.

e. Carrying costs associated with the substantial inventory balance that FPL will target for maintaining in the Gas Storage Project in order to provide the reliability and volatility-reduction benefits described above.

13. FPL proposes to recover the Gas Storage Project costs as gas transportation charges and hedging transaction costs via the Fuel Clause. Specifically, FPL proposes to charge for the cost components identified above as follows:

a. <u>Monthly Storage Reservation Charge</u>: This will be charged to the Fuel Clause as a gas transportation charge each month as it is incurred.

b. <u>Base Gas:</u> If FPL leases Base Gas, it will charge the lease payment to the Fuel Clause as a gas transportation charge each month as it is incurred. If FPL elects instead to provide its own Base Gas, it will charge the value of that natural gas to the Fuel Clause as a gas transportation charge in the month when that gas is injected into the Gas Storage Facility.[1] Eventually, the Base Gas will be withdrawn and consumed by FPL. At the time that a quantity of Base Gas is withdrawn, FPL will credit to the Fuel Clause the

[1] The Commission has historically allowed electric utilities to charge "non-recoverable oil" to the Fuel Clause at the time that the oil is placed into the utilities' storage tanks. *See* Order No. 12645, Docket No. 830001-EI, dated November 3, 1983. Base Gas will serve the same purpose in the Gas Storage Facility as non-recoverable oil serves in FPL's oil storage tanks and should be treated similarly.

amount that it had previously charged to the Fuel Clause for that quantity of Base Gas.

c. Injection/Withdrawal Charges: Fuel retention and commodity charges for the injection and withdrawal of natural gas will be charged to the Fuel Clause as gas transportation charges.

d. Monthly Inventory Insurance Charge. If FPL elects to pay MoBay for this insurance, the monthly inventory insurance charge will be charged to the Fuel Clause as a gas transportation charge each month as it is incurred. If FPL provides its own insurance at a lower cost than the Monthly Inventory Insurance Charge, it will charge the actual cost of its premiums to the Fuel Clause as a gas transportation charge in the month when those premiums accrue.

e. Inventory Carrying Costs. The inventory carrying costs will be calculated by applying the regulatory overall cost of capital times the average monthly inventory balance. This calculation is consistent with the methodology used to calculate the return on investment in all of FPL's retail cost recovery clauses. This amount will be charged to the Fuel Clause as part of the weighted average cost of gas as burned.

14. None of the costs of the Gas Storage Project are currently recovered through FPL's base rate charges or any other recovery mechanism.

15. As described in section 5, FPL has utilized small scale natural gas storage arrangements for several years. Initially, FPL purchased storage capacity on a short-term basis, but in 2003 entered into a long-term storage arrangement with Bay Gas Storage Company Limited, Ltd. (the "Bay Gas Storage Contract"). FPL has included costs associated with the Bay Gas Storage Contract in the Fuel Clause since the contract's inception in 2003. However, until now FPL has inadvertently failed to include in the Fuel Clause the carrying cost associated with natural gas inventory that it maintains at the Bay Gas storage facility. Consistent with Paragraph 13(e) above and commencing upon approval of this petition, FPL proposes to begin including in the Fuel Clause the natural gas inventory carrying costs associated with the Bay Gas Storage Contract or any successors thereto.

No Material Facts in Dispute

16. FPL is not aware of any dispute regarding the material facts contained in this petition.

Conclusion and Request for Relief

17. For the reasons discussed above and in Mr. Yupp's affidavit, the Gas Storage Project will serve as a physical hedge that provides reliability and volatility-reduction benefits to FPL's customers; its costs are not currently recovered through FPL's base rates; and recovery of those costs as gas transportation charges and hedging transaction costs via the Fuel Clause is consistent with established Commission practice and the Hedging Order. Accordingly, recovery of reasonably and prudently incurred costs for the project through the Fuel Clause is appropriate.

WHEREFORE, FPL respectfully requests that the Commission enter an order approving recovery of the reasonably and prudently incurred costs of the Gas Storage Project through the Fuel Clause.

Respectfully submitted,

John T. Butler, Esq.
Senior Attorney
Florida Power & Light Company
9250 W. Flagler Street
Miami, Florida 33174
(305) 552-3867
(305) 552-3865 (Fax)

By: ______________________
John T. Butler
Fla. Bar No. 283479

EXHIBIT A

STATE OF FLORIDA)
) **AFFIDAVIT OF GERARD YUPP**
PALM BEACH COUNTY)

BEFORE ME, the undersigned authority, personally appeared Gerard Yupp who, being first duly sworn, deposes and says:

1. My name is Gerard Yupp. I am currently employed by Florida Power & Light Company ("FPL") as Director of Wholesale Operations in the Energy Marketing and Trading Division. I have personal knowledge of the matters stated in this affidavit.

2. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer and worked in the area of relay engineering. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In May of 1995, I joined Cytec Industries as a plant electrical engineer where I worked until October of 1996. At that time, I rejoined FPL as a real-time power trader in the Energy Marketing and Trading Division. Since rejoining FPL in 1996, I have moved from real-time power trading to short-term power trading, power trading manager and assumed my current position in December 2004.

3. I am responsible for managing the daily activities of the Wholesale Operations Group. Daily activities include natural gas and fuel oil procurement, fuel allocation and fuel burn management for FPL's oil and/or natural gas burning plants, coordination of plant outages with wholesale power needs, real-time power trading, short-term power trading, transmission procurement and scheduling. Longer-term initiatives include fuel planning and evaluating opportunities within the wholesale power markets based on forward market conditions, FPL's outage schedule, fuel prices and transmission availability.

4. FPL depends upon natural gas for a substantial portion of the electric energy it generates each year. For example, slightly over 50% of FPL's 2005 total generated MWh were produced with natural gas. Unlike coal, oil and nuclear fuel, it is impractical to store significant quantities of natural gas at the generating facilities where it is burned. This means that, in the absence of off-site storage arrangements, FPL must depend on a constant supply of natural gas into the pipelines that deliver it to FPL. Any disruptions of those sources of supply by hurricanes or other events can result in nearly immediate and quite substantial reductions in the amount of natural gas available for FPL's gas-fired generating facilities.

5. MoBay Gas Storage Hub, owned and operated by Falcon Gas Storage, Inc (www.falcongasstorage.com) is a HDMC (high-deliverability, multi-cycle) reservoir gas storage facility of up to 50+ Bcf of storage capacity in compartmentalized high-quality gas reservoirs. Set for phased development starting with Phase I working gas capacity of 12 Bcf and up to 50+ Bcf of working gas capacity available (Phase II) with maximum injection/withdrawal capabilities of 1.2 Bcfd+ each which will be interconnected to four different interstate pipelines: Florida Gas Transmission (FGT) Zone 3, Gulfstream Natural Gas (Gulfstream), Gulf South Pipeline (Gulf South) Zone 4, and Transcontinental Gas Pipeline (Transco) Station 85 / Zone 4. When fully developed, MoBay will be the largest, most southeasterly underground natural gas storage facility in the United States. MoBay's primary storage facilities (such as compression, controls, pipeline interconnections and meter stations) will be located

onshore in Coden, Alabama next to Gulf Stream's main compression station at the confluence of major market and supply area pipeline systems and processing plants serving natural gas and electric utilities in the Southeast and Northeast markets. It will be the only proposed HDMC storage facility of any kind capable of directly connecting with the Gulfstream pipeline system serving the Florida market. HDMC (high-deliverability, multi-cycle) reservoir storage provides shorter and lower development costs per unit than other gas storage facilities. In turn this provides operational service at far less cost than other facilities such as salt caverns. HDMC reservoir storage provides high Peak Day deliverability, very large storage volumes, allows inventory to be cycled from 1-6 times annually while virtually eliminating the kinds of catastrophic failure risks that have plagued Salt Cavern storage on a number of different occasions (e.g., Moss Bluff). Maintenance and overall site development for HDMC reservoir storage also provides far less environmental impact in development and operations. HDMC reservoir storage is conducted in depleted oil and gas reservoirs that are known geologic structures, having held oil and gas in well formed and identified geologic structures for millions of years, giving confidence in the safe, effective, active and long term storage of natural gas, unlike man-made caverns that have been known to leak and/or experience catastrophic failures, including fires and explosion. (See Attachment 1).

6. The Gas Storage Project will substantially increase FPL's ability to hedge the physical supply of natural gas, resulting in a significant increase in system reliability and a reduction in natural gas price volatility. The location of the Gas Storage Facility is close to the growing natural gas loads in the Florida markets and can provide benefits to all natural gas consumers in Florida. Additionally, this location at the termini of the Gulfstream pipeline and FGT Mobile Bay pipelines will allow FPL to realize the maximum benefit of its existing firm transportation arrangements and avoid "pancaked" pipeline transportation fees.

7. FPL will be an "anchor tenant" of the Gas Storage Facility. It will be entitled to store up to 6 million dekatherms at the Gas Storage Facility, which represents 50% of the facility's Phase I capacity. Six million dekatherms corresponds to approximately five days of FPL's typical natural gas consumption. Thus, the Gas Storage Project will substantially improve FPL's ability to withstand disruptions to the Gulf of Mexico production facilities, such as occurred in the 2005 hurricane season, without having to reduce the output of its gas-fired generating facilities. The Destin/Mobile Bay area of the Gulf of Mexico is highly susceptible to production shut-ins due to the threat or impact of extreme weather events. Approximately 48% of FPL's firm gas transportation capacity, on FGT and Gulfstream, is tied to off-shore production in the Destin/Mobile Bay area. Production shut-ins in this area have a significant impact on the availability of natural gas to supply both the FGT and Gulfstream pipelines. To the extent that production is curtailed in the area, FPL must find alternate means to supply natural gas into the FGT and Gulfstream pipelines. FPL's options for obtaining natural gas supply for Gulfstream after production shut-ins are currently very limited. The Gas Storage Project will provide FPL with an alternate gas supply source directly connected to the Gulfstream pipeline. FPL will also be able to deliver gas into FGT from the Gas Storage Facility. Natural gas supplies from this area are also subject to high price volatility, not only during extreme events, but also during high demand periods due to location and operational reasons. Therefore, the ability to store a substantial volume of natural gas will help reduce FPL's vulnerability to natural gas supply curtailments in the Destin/Mobile Bay area and help limit FPL's exposure to the volatility inherent in relying on spot market gas or alternate fuels during severe weather events and periods of high demand. The Gas Storage Facility will also enhance FPL's ability to respond to day-to-day and intra-day changes to its natural gas requirements.

8. In order to secure a substantial participation in the Gas Storage Facility and to help ensure the facility's financial viability, FPL entered into a Firm Storage Service Precedent Agreement (the "Precedent Agreement") with MoBay on April 1, 2006. The Gas Storage Facility is scheduled to go into service between December 31, 2007 and July 1, 2008. FPL is entitled under the Precedent Agreement to terminate its involvement anytime after December 31, 2007 if the Gas Storage Facility is not yet in service and MoBay is not exercising commercially reasonable efforts to complete it. [redacted] A copy of the Precedent Agreement is provided as Attachment 2.

9. As presently contemplated, the Gas Storage Project will entail the following financial responsibilities for FPL:

a. A monthly storage reservation charge of [redacted] per dekatherm of the maximum storage quantity ("MSQ"). At FPL's expected MSQ of 6 million dekatherms, this would be [redacted] per month.

b. In order to maintain sufficient pressure in the Gas Storage Facility to permit natural gas withdrawals as needed, FPL will either have to provide or lease from MoBay an amount of gas equal to 50% of its MSQ (this is referred to as "Base Gas" and would amount to 3 million dekatherms for FPL). Based on MoBay's pricing information, FPL expects that providing its own Base Gas will be less expensive than leasing it from MoBay for the term of the agreement.

c. A charge of 1% fuel retention for each dekatherm of natural gas that is injected into and 1% fuel retention for each dekatherm withdrawn from the Gas Storage Facility. Fuel retention is the percentage of each injected or withdrawn volume of fuel that the Gas Storage Facility retains to compensate for fuel used in the compression process. In addition to fuel retention, a commodity charge of [redacted] per dekatherm will be applied to all injections and withdrawals of natural gas. This commodity charge compensates the Gas Storage Facility for operation and maintenance expenses.

d. A monthly inventory insurance charge of $0.0125 per dekatherm, applied to the total of a tenant's MSQ and Base Gas. For FPL, this would be 9 million dekatherms times $0.0125, or $112,500 per month. This insurance protects against the risk of fire, sabotage and other risks that could result in losing all or part of the volume of the stored gas (for which tenants retain the risk of loss). FPL has the option to obtain this insurance itself rather than paying the monthly inventory insurance charge if deemed beneficial to FPL's customers.

e. Carrying costs associated with the substantial inventory balance that FPL will target for maintaining in the Gas Storage Project in order to provide the reliability and volatility-reduction benefits described above.

10. Attachment 3 is a table showing that the storage costs under the Gas Storage Project are favorable in comparison to FPL's existing storage arrangements. [redacted]

11. None of the costs of the Gas Storage Project are currently recovered through FPL's base rate charges or any other recovery mechanism. FPL currently recovers the costs of natural gas storage arrangements through the Fuel Clause, as part of its gas transportation charges. Attachment 4 is MFR B-18 for the Test Year 2006 showing that natural gas inventory was not included in FPL's MFR filing in Docket No. 050045-EI and, therefore, the carrying costs associated with natural gas inventory is not included in FPL's base rate charges.

12. Affiant says nothing further.

Gerard J Yupp

Gerard Yupp

SWORN TO AND SUBSCRIBED before me this 27 day of April 2006, by Gerard Yupp, who is personally known to me or who has produced ______________ (type of identification) as identification and who did take an oath.

Debra Ann Dominguez

Notary Public, State of Florida

My Commission Expires: April 20, 2008

NOTARY PUBLIC STATE OF FLORIDA
Debra Ann Dominguez
Commission # DD312184
Expires: April 20, 2008
Aaron Notary 1-800-350-5161

LDC FORUM
Atlanta, Georgia April 2006

Michael E. Moore
Director of Marketing East Region

FALCON GAS STORAGE

MOBAY STORAGE HUB

Falcon Gas Storage Company, Inc.

Falcon Gas Storage Company, Inc.

- Falcon Gas Storage Company, Inc. was founded in 2000 to develop and operate underground natural gas reservoir storage facilities.
- Today, Falcon is the largest independent developer/operator of underground natural gas storage in the U.S.
- Operates 20 Bcf of high-deliverability reservoir storage capacity in Texas.
- Falcon proposes to develop the MoBay Storage Hub in Mobile County, AL.

FALCON GAS STORAGE

MoBay Overview

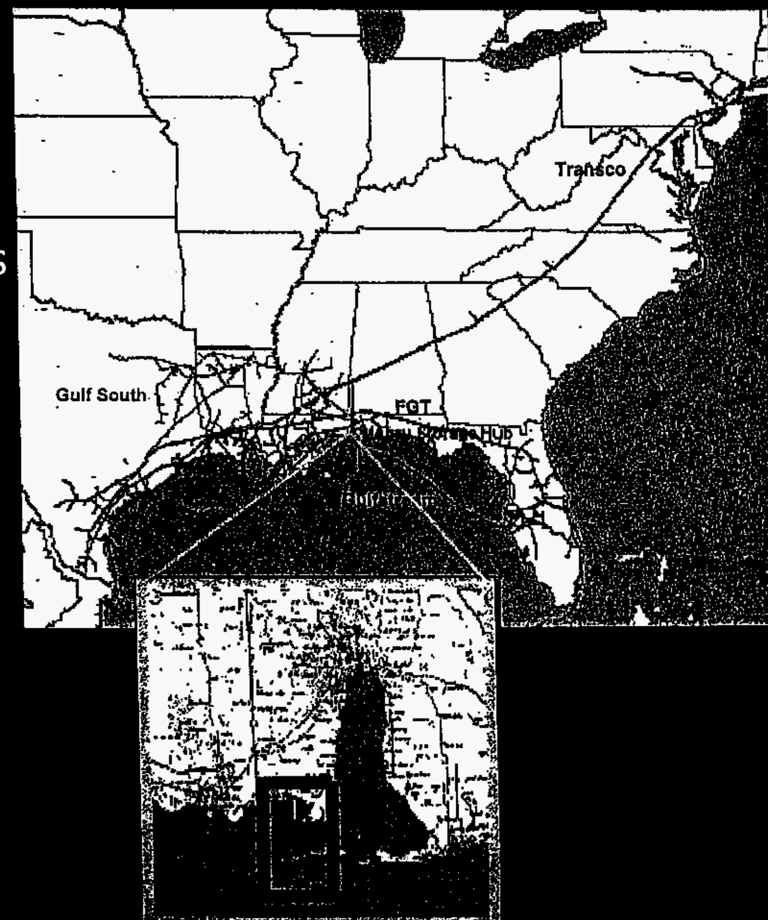
- Falcon acquired the MoBay reservoirs and production facilities from Callon Petroleum in 2003.
- Ideal porosity and permeability characteristics for HDMC gas storage.
- Ideal location to directly connect with multiple markets and supply points.
- Multiple, compartmentalized reservoirs can be developed in phases providing significant amount of new storage capacity from a single location next to major interstate pipelines and proposed LNG facilities (cumulative production: 75.8 Bcf).
- Falcon has operated MoBay production since January 2003.
- Conversion to storage operations uses standard drilling, completion, pipeline and compression technology.
- Designed for continuous operations during extreme weather events.

FALCON
GAS STORAGE

Strategic Location

Ideal storage hub location:

- Offshore production
- Gas processing facilities
- Proposed LNG import facilities
- Major interstate pipelines serving Southeast and Northeast markets
  - Gulfstream
  - Transco
  - GulfSouth
  - Florida Gas Transmission



Strategic Location

Direct Access to Major Markets/Supply

FALCON GAS STORAGE

Southeast/Florida:

- Gulfstream (Destin via backhaul on Gulfstream)
- Florida Gas Transmission (via Transco MBL) -- Zone 3
- GulfSouth Pipeline -- Zone 4

Northeast Demand:

- Transco Mobile Bay Lateral - Zone 4A

Supply:

- Proposed LNG import terminals in Pascagoula/Mobile (5)
- ExxonMobil Mary Ann Plant
- Shell Yellow Hammer Plant
- Dauphin Island Gathering Partners
- Mobile Bay Processing Partners Plant
- Williams Mobile Bay Processing Plant

South East Expansion "Open Seasons"

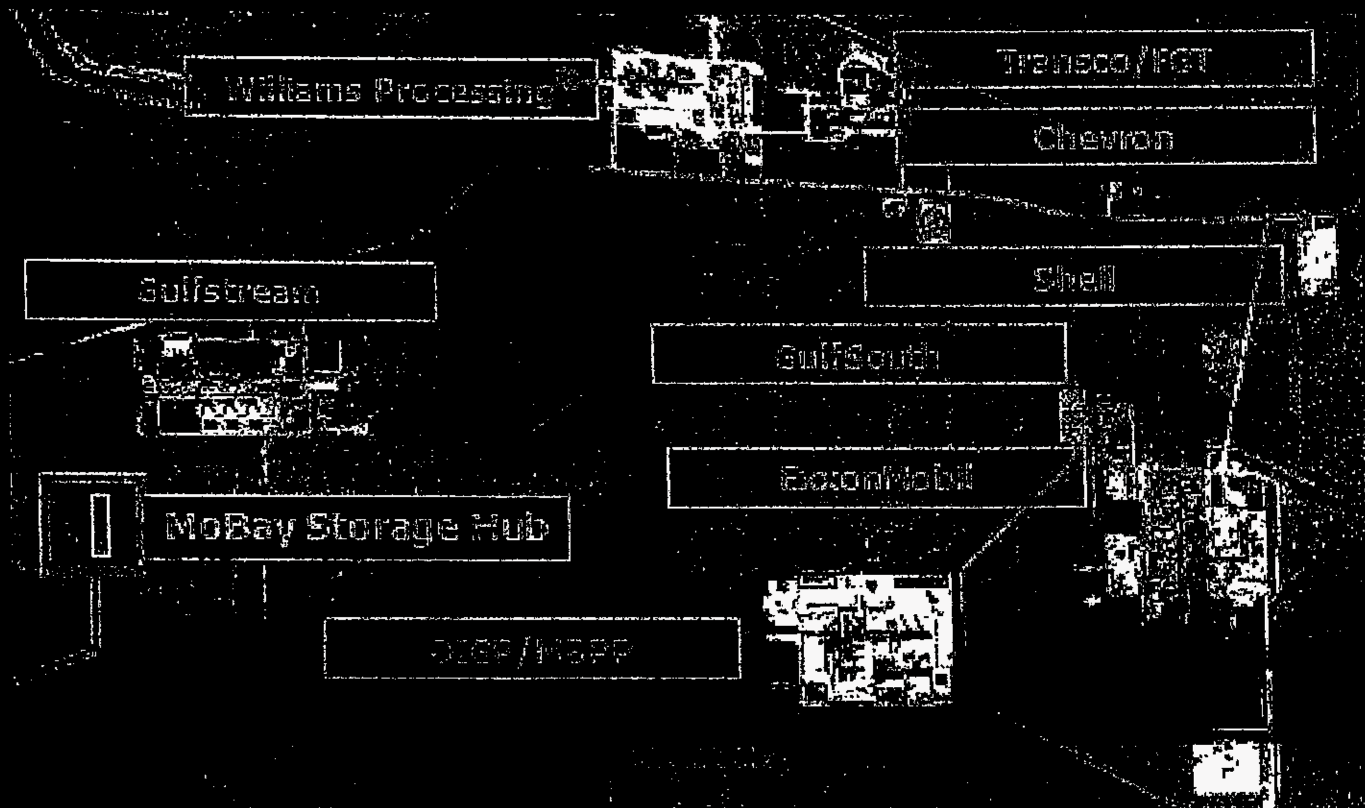
FALCON GAS STORAGE

- **Falcon's MoBay Storage and Market Hub** Open Season ran 2/15-3/15 adding 50 Bcf storage capacity in three phases
- **Duke-Center Point Southeast Supply Header** 1/20/05 to 2/18/06 connecting Perryville Hub to Gulfstream with 1 Bcf capacity
- **Gulfstream Pipeline Expansion** Open Season for 200 mmcf compression ran 2/1 to 3/1/2006
- **Gulfstream Reverse Open Season** for shipper capacity that can be turned back running 3/10 to 4/7/2006
- **Transco Mobile Bay Lateral** 700 mmcf capacity expansion from Station 85 to a new Gulfstream Point ran 2/8 to 3/10 2006

FALCON GAS STORAGE

Strategic Location

Direct Access to Major Markets/Supply



Facilities

Onshore and Offshore

Onshore:

- Compression/Separation/ Dehydration
- Metering
- 36" Pipeline (7 mi)

Offshore:

- 36" Pipeline (10 mi)
- Wells
- 2 existing Cat 5 platforms
- Flow lines
- 5-10' water depth

FALCON GAS STORAGE

Strategic Location

Downstream of pipeline/processing constraints

- Most southeasterly storage location in the U.S.
- Multiple pipeline interconnects serving multiple markets.
- Only storage facility with direct access to Gulfstream.
- Reduces transport cost required for upstream storage holders.
- Telescoping capacity on Transco FGT limits takeaway capacity at upstream storage locations.
- Offers stronger pricing points for LNG imports: SE (Florida)/Atlantic Seaboard.
- Access to significant processing capacity at Mobile Bay.
- Well-positioned for eventual development of resources in the Eastern Gulf of Mexico.

FALCON GAS STORAGE

Market Demand

Results of Non-Binding Open Season (03/15/06)

Working Gas:	34 Bcf
Maximum Withdrawal:	1.3 Bcfd
Maximum Injection:	0.7 Bcfd
Services:	1-9 cycle storage
Term of service:	3-15 yrs
Shipper Type:	Electric utilities, LDCs, LNG terminals, Marketers, Producers, Industrials
Requested in-service:	Fall 2007

FALCON GAS STORAGE

Market Demand

Services and Rates Requested

- Firm and Interruptible Storage Services
- Firm and Interruptible Wheeling Services
- Park and Loan Services
- Market-Based Rates

Market Demand

Precedent Agreements Executed as of 04/01/06

Working Gas:	10 Bcf
Maximum Withdrawal:	400 mmcfd
Maximum Injection:	200 mmcfd
Services:	2-4 cycle service
Term:	3-15 yrs

FALCON GAS STORAGE

Phase I

- Construct new onshore compressor plant and meter stations:
  - Gulfstream
  - Transco MBL
  - GulfSouth
  - Florida Gas Transmission
- Construct new 36″ pipeline connecting onshore compressor station with off-shore facilities
- Reservoirs converted to storage:
  - Northwest Dauphin Island
  - Northeast Petit Bois
  - North Dauphin Island - West Section
- Total working gas: 12 Bcf

FALCON GAS STORAGE

Phase II Expansions

- Additional storage injection/withdrawal wells
- Additional compression (up to 30,000 total hp)

Total working gas capacity:	50 Bcf
Maximum Withdrawal Capacity:	1 Bcfd
Maximum Injection Capacity:	1 Bcfd

Timeline

File State and Federal Applications	May 2006
Start construction (To meet requested Phase I in-service date)	Winter 2006
Phase I in-service	October 2007
Phase II in-service	Summer 2008 – Spring 2009

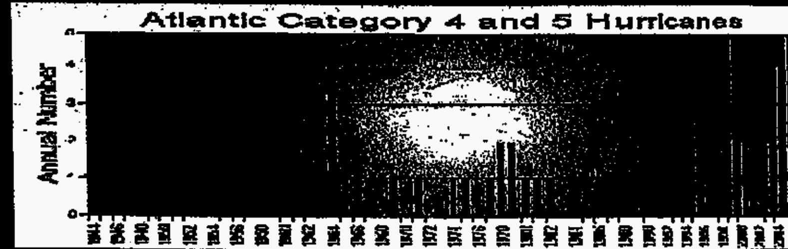
Storage and NatGas Volatility

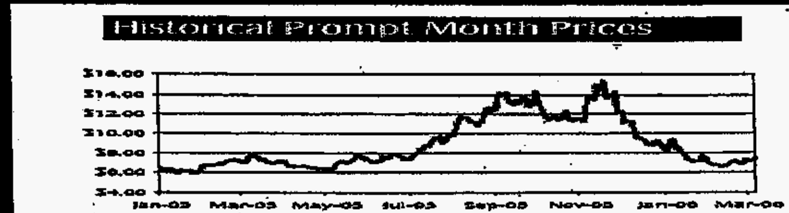
FALCON GAS STORAGE

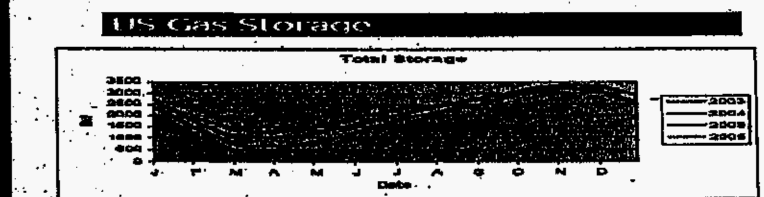
- Unseasonably warm winter-hurricane wildcard
- Current and planned gas storage committed
- Gas in-storage at all time highs
- Industrials re-emerging on base load side
- Economic growth strong
- Pipeline capacity into SE fully utilized
- Quickly changing supply/infrastructure demographics
- LNG is developing....issues are abundant
- Price signals conflicting
- What's Coal doing?
- Impacts long term planning decisions

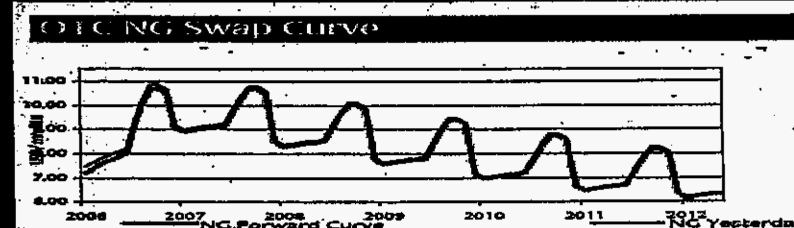
Market Drivers Today

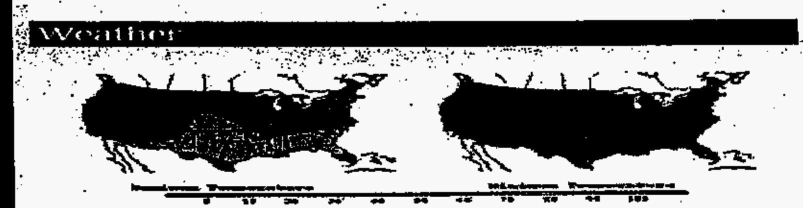
- The South and Northeast recorded the lowest regional unemployment rates in January, 4.4 and 4.5 percent, respectively
- Among the nine geographic divisions, the South Atlantic posted the lowest unemployment rate in January, 3.9 percent.
- Florida and Virginia, 3.0 percent each
- West Virginia and Alabama 3.8 percent each
- Georgia 4.8%, North Carolina 4.3% Louisiana 4.8%
- South Carolina 6.2 percent, Mississippi 8.4%,











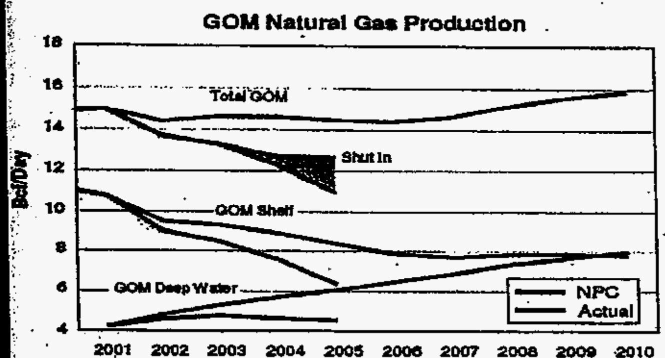
Depleting GOM NatGas Production

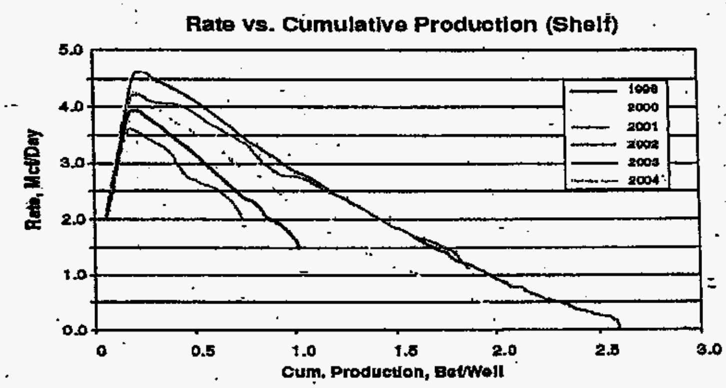
FALCON GAS STORAGE

Source: NPC Report 2005

Natural Gas Supply Overview

Gulf of Mexico Basin (Shelf/Deepwater)





- GOM shelf gas production has declined by nearly 2.6 Bcf/day, since 2001 (excluding effect of hurricanes); opportunities continue to become smaller; hurricanes reduced gas production by an additional 1.7 Bcf/day in 2005.
- Deepwater projects are delayed and less gas prone than expected.
- Sustaining GOM production will be challenging given recent disappointing exploration results.

Conclusion

- Right Place
- Right Time
- Right Facilities
- Right Markets
- Right Size
- Right Customer Base
- Thank You

FIRM STORAGE SERVICE PRECEDENT AGREEMENT

This Firm Storage Service Precedent Agreement ("Precedent Agreement") is entered into this ______ day of ___________, 2006, by and between **MoBay Storage Hub, Inc.** ("Owner"), a Delaware Corporation, and Florida Power & Light Company, a corporation formed under the laws of Florida ("Shipper"). Owner and Shipper are referred to herein individually as a "Party" and collectively "Parties".

WITNESSETH:

WHEREAS, Owner proposes to construct, own, and operate a subsurface natural gas storage facility and appurtenant facilities in Mobile, Alabama ("MoBay Storage Project") and to engage in the storage of natural gas in interstate commerce subject to the jurisdiction of the Federal Energy Regulatory Commission ("Commission" or "FERC"); and

WHEREAS, Shipper desires Owner to store Shipper's natural gas on a firm basis in the MoBay Storage Project; and

WHEREAS, subject to the terms and conditions set forth in this Precedent Agreement, Owner is willing to endeavor to construct, install or cause to be constructed or installed the necessary facilities and to provide the firm storage service as described in this Precedent Agreement;

NOW THEREFORE, in consideration of the mutual covenants and agreements herein contained, and intending to be legally bound, Owner and Shipper stipulate and agree as follows:

1. <u>Governmental Authorizations</u>. Subject to the terms and conditions of this Precedent Agreement, Owner shall use commercially reasonable efforts to obtain from all governmental and regulatory authorities having competent jurisdiction over the MoBay Storage Project, including the Commission, the authorizations and/or exemptions ("Governmental

Authorizations") that Owner determines are necessary: (i) to construct, install, own, maintain, and operate (or cause to be constructed, installed, owned, maintained, and operated) the facilities necessary to render the firm service as contemplated in this Precedent Agreement; (ii) to provide firm storage services at market-based rates; and (iii) to perform its obligations under the Firm Storage Service Agreement ("Service Agreement") attached hereto as Exhibit A and made a part hereof. Owner shall file and prosecute any and all applications for such Governmental Authorizations, any supplements and amendments thereto, and, if necessary, any court review, in such manner as it deems to be in its best interest. Shipper expressly agrees to support and cooperate, and to not oppose, obstruct, or otherwise interfere with, in any manner whatsoever, the efforts of Owner to obtain all Governmental Authorizations.

2. <u>Execution of Service Agreement</u>. Contemporaneously with the execution and delivery of this Precedent Agreement, Shipper and Owner have executed the Service Agreement, which provides for a firm storage reservation capacity of 6,000,000 Dth ("Initial Capacity"). Owner shall provide, and Shipper shall take and pay for, service pursuant to the Service Agreement as of the in-service date of the MoBay Storage Project established pursuant to Paragraph 4; provided, however, that the Service Agreement shall be terminated prior to such date if this Agreement is terminated pursuant to subparagraphs (b), (c), or (d) of Paragraph 6 or subparagraph (b) of Paragraph 4 and in such case neither Shipper nor Owner shall have any obligations with respect to the Service Agreement.

3. <u>Design and Implementation of Facilities</u>. Owner will undertake the design of facilities and any other preparatory actions necessary for Owner to complete and file its certificate application(s) with the Commission. Upon satisfaction or waiver of the conditions precedent set forth in subparagraphs (a), (b), (c), (d), (e), and (g) of Paragraph 5, Owner shall proceed with the

necessary final design of facilities, acquisition of materials, supplies, properties, rights-of-way and any other necessary preparations to implement the firm service under the Service Agreement as contemplated in this Precedent Agreement. Prior to the satisfaction or waiver of the associated conditions precedent, Owner shall have the right, but not the obligation, to proceed with the foregoing activities. If Owner elects to proceed with some of the foregoing activities prior to satisfaction of the associated condition precedent(s), such actions shall not constitute waiver of such condition precedent(s) absent written notice to that effect from Owner.

4. <u>Construction of Facilities and Commencement of Service; Expansions</u>.

(a) Upon satisfaction or waiver of the conditions precedent set forth in subparagraphs (a), (b), (c), (d), (e), and (g) of Paragraph 5, Owner shall use commercially reasonable efforts to construct the authorized facilities necessary to implement the firm service contemplated in this Precedent Agreement and the Service Agreement on or about December 31, 2007 ("Proposed In-Service Date"); provided, however, that in the event Owner's failure to complete construction of its facilities and commence the storage services contemplated hereunder is due to Owner's Force Majeure, the Proposed In-Service Date shall be extended for each day of force majeure up to a maximum of one hundred eighty (180) days. "Owner's Force Majeure" shall mean any cause whether of the kind enumerated herein or otherwise, not reasonably within the control of Owner, that renders Owner unable, wholly or in part, to construct the MoBay Storage Project. Owner's Force Majeure shall include, but not be limited to, acts of God; strikes, lockouts and industrial disputes or disturbances; inability to secure or delays in obtaining material permits or material Governmental Authorizations, material easements or rights-of-way, impossibility to secure labor, materials, supplies or inability to secure materials by reason of allocations promulgated by authorized governmental agencies; arrests and restraints of governments and people;

interruptions by government or court orders; present and future valid orders, decisions or rulings of any government or regulatory entity having proper jurisdiction; acts of the public enemy; vandalism; wars; riots; civil disturbances; blockades; insurrection; epidemics; landslides; lightening; tornadoes; hurricanes; earthquakes; fires; storms; floods; washouts; inclement weather which necessitates extraordinary measures to maintain operations; explosions; breakage, accidents and/or maintenance to plant facilities including machinery, lines of pipe, accidents and/or unscheduled maintenance of wells or subsurface storage caverns or reservoirs; testing (as required by governmental authority or as deemed necessary by Owner for the safe operation of the facilities required to perform the services hereunder); and the making of repairs or alterations to pipelines, storage, caverns or reservoirs and plant facilities including pipeline repairs of transporter(s) with which the MoBay Storage Project interconnects. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of Owner, and that Owner shall not be required to settle strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of Owner. If, notwithstanding the commercially reasonable efforts of Owner, Owner is unable to commence the firm service for Shipper as contemplated herein by the Proposed In-Service Date, Owner will continue to proceed with commercially reasonable efforts to complete arrangements for such firm service and commence the firm service for Shipper at the earliest practicable date thereafter. Owner will not be liable nor will this Precedent Agreement or the Service Agreement be subject to cancellation (except as specifically provided pursuant to Paragraph 6) if Owner is unable to complete the construction of such authorized and necessary facilities and commence the firm service contemplated herein by the Proposed In-Service Date, except as provided in Paragraph 4(b).

(b) If Owner is unable to complete construction of its facilities and commence the storage services contemplated hereunder by the Proposed In-Service Date (as such date may be extended pursuant to Paragraph 4(a)), then Shipper shall have the right after the Proposed In-Service Date, to give Owner notice of cancellation of this Precedent Agreement and the firm storage agreement to be effective upon thirty (30) days from the date of written notice of cancellation to Owner; provided, however, that if and for so long as Owner continues to exercise commercially reasonable efforts to construct its facilities and commence the storage services, Shipper shall not be entitled to exercise its termination right until one hundred eighty (180) days after the Proposed In-Service Date.

5. <u>Conditions Precedent</u>. The Parties' rights and obligations under Paragraph 4(a) are expressly made subject to satisfaction, or waiver by Owner, of the conditions precedent (a), (b), and (c) below and the satisfaction, or waiver by Shipper, of the conditions precedent (d), (e), (f), and (g) below:

(a) receipt in a form acceptable to Owner in its sole discretion by [redacted] of the Governmental Authorizations, except for those authorizations typically received after the commencement of construction;

(b) procurement by [redacted] of all necessary rights-of-way easements or permits in form and substance acceptable to Owner in its sole discretion;

(c) receipt by Owner of approval by its Board of Directors no later than ten (10) days of the satisfaction or waiver of condition precedent 5(d) below, from its Management Committee or similar governing body to proceed with this Precedent Agreement and the Service Agreement;

(d) receipt by Shipper of approval no later than ten (10) days of the execution of this Precedent Agreement, from its Management Committee or similar governing body to proceed with this Precedent Agreement and the Service Agreement;

(e) submission by Owner to the Federal Energy Regulatory Commission of an application pursuant to Section 7 of the Natural Gas Act for a certificate of public convenience and necessity to construct, own, and operate the MoBay Storage Project by [redacted]

(f) commencement by Owner of bona fide construction of the MoBay Storage Project no later than [redacted] For purposes of this Precedent Agreement, Owner shall be deemed to have commenced bona fide construction of the MoBay Storage Project facilities when Owner has awarded the construction contract(s) to its general construction contractor(s) and such contractor(s) certifies to Shipper in writing that it has been released to commence construction of the MoBay Storage Project facilities; and

(g) receipt in a form acceptable to Shipper in its sole discretion by [redacted] of approval from the Florida Public Service Commission for Shipper to recover through the fuel cost recovery clause costs Shipper incurs pursuant to the obligations set forth in this Precedent Agreement and the Service Agreement; provided, however, that Shipper may, upon written notice provided to Owner no later than [redacted] extend the deadline for the satisfaction of this condition precedent 5(g) by up to sixty (60) days; provided further that the deadlines applicable to the conditions precedent 5(a), 5(b), 5(e), and 5(f) above shall be extended by the same number of days that Shipper elects to extend the deadline for this condition precedent 5(g).

6. <u>Term and Termination</u>.

(a) This Precedent Agreement shall become effective on the date set forth above and, unless terminated pursuant to Paragraph 4(b) or subparagraphs (b), (c), or (d) of this Paragraph 6, will terminate by its express terms on the date of commencement of service under the Service Agreement, as provided for in Paragraph 4(a), and thereafter Owner's and Shipper's rights and obligations related to the storage transaction contemplated herein shall be determined pursuant to the terms and conditions of such Service Agreement and Owner's FERC Gas Tariff, as effective from time to time, except that Shipper shall be required to comply with the creditworthiness provisions of Paragraph 7 for the term of the Service Agreement.

(b) At any time prior to the commencement of bona fide construction, Owner may terminate this Precedent Agreement at any time upon fifteen (15) days' prior written notice to Shipper if Owner, in its sole discretion, determines for any reason that the MoBay Storage Project contemplated herein is no longer economically viable or if substantially all of the other precedent agreements, service agreements or other contractual arrangements for the firm service to be made available by the MoBay Storage Project are terminated, other than by reason of commencement of service.

(c) Failure of Conditions Precedent.

(i) If a condition precedent set forth in Paragraphs 5(a) through (c) has not been fully satisfied, or waived by Owner pursuant to the terms of Paragraph 5, by the applicable date specified therein or if a condition precedent set forth in Paragraphs 5(d) and (g) has not been fully satisfied, or waived by Shipper pursuant to the terms of Paragraph 5 by the applicable date specified therein, then Owner may thereafter terminate this Precedent Agreement by giving ninety (90) days' prior written notice of its intention to terminate to Shipper; provided, however, if the condition precedent is satisfied, or waived by Owner or Shipper, as applicable, pursuant to the terms of Paragraph 5, within such ninety (90)-day notice period, then termination will not be effective; provided further that the foregoing cure period shall not apply to the condition precedent set for in Paragraph 5(g).

(ii) If a condition precedent set forth in Paragraphs 5(d) through (g) has not been fully satisfied by Owner or Shipper, as applicable, or waived by Shipper pursuant to the terms of Paragraph 5, by the applicable date specified therein, then Shipper may thereafter terminate this Precedent Agreement by giving forty-five (45) days' prior written notice of its intention to terminate to Owner, such notice to be given no later than ninety (90) days after the applicable date for satisfaction of the condition precedent; provided, however, if the condition precedent is satisfied, or waived by Shipper, pursuant to the terms of Paragraph 5, within such forty-five (45)-day notice period, then termination will not be effective; provided further that the foregoing cure period shall not apply to the condition precedent set for in Paragraph 5(g).

(d) If Shipper (i) fails to perform, in whole or in part, its material duties and obligations hereunder or (ii) interferes with or obstructs the receipt by Owner of the Governmental Authorizations contemplated by this Precedent Agreement as requested by Owner and Owner as a result of such interference or obstruction by Shipper, does not receive the Governmental Authorizations in form and substance as requested by Owner or does not receive such authorizations and/or exemptions at all, then Owner may, in addition to any other remedies Owner may have at law or equity, thereafter terminate this Precedent Agreement by giving sixty (60) days' prior written notice of its intention to terminate to Shipper; provided, however, if the Shipper cures its failure to perform under clause (i) above, within such sixty (60)-day notice period, then termination will not be effective.

(e) Owner agrees that the term of the Service Agreement shall be for fifteen (15) years ("Primary Term").

7. Creditworthiness.

(a) Applicability. Shipper covenants that, beginning on the commencement of service pursuant to the Service Agreement and for so long as the Service Agreement remains in effect Shipper shall, comply with the creditworthiness requirements set forth in Owner's FERC Gas Tariff, as amended by this Paragraph 8. The provisions of this Paragraph 8 shall survive the termination of this Precedent Agreement.

(b) Alternative Forms of Security. The following provisions shall replace subsections (i), (ii) and (iii) of Section 2.4(c) of the General Terms and Conditions of Owner's FERC Gas Tariff:

(i) Shipper may post and maintain in effect a standby, irrevocable Letter of Credit (aa) issued by a financial institution with combined capital and surplus of at least $500,000,000 that is rated at least A by Standard & Poor's Corporation and A2 by Moody's Investor Services, Inc., (bb) that provides for partial drawdowns, and (cc) in form and substance satisfactory to Owner. A form of letter of credit is available from Owner. The amount of the Letter of Credit shall be equal to no less than the value of applicable transportations charges for Shipper's Maximum Storage Quantity (as defined in the Service Agreement) for the lesser of (i) twenty-four months or (ii) the remaining term of the Service Agreement. If Owner draws funds under the Letter of Credit, Shipper shall replenish the Letter of Credit to the required value specified herein no later than five (5) Business Days after such drawing. As Owner recovers the cost of such facilities through its rates, the security required shall be reduced accordingly until the amount is reduced to the value of three (3) months' worth of applicable storage charges.

(ii) Shipper may provide a guaranty of all of Shipper's obligations under the Service Agreement granted to Owner by the Shipper's parent, affiliate or third party with a rating of at least the Minimum Acceptable Credit Rating, which guarantee shall be in form and substance acceptable to Owner. A form of guaranty is available from Owner.

(iii) Shipper may prepay for service via cleared check, or wire transfer. The amount of the prepayment shall be equal to no less than the value of applicable transportations charges for Shipper's Maximum Storage Quantity (as defined in the Service Agreement) for the lesser of (i) twenty-four months or (ii) the remaining term of the Service Agreement. Prepayment amounts shall be deposited in an interest-bearing escrow account if such an account has been established by Shipper and Owner reasonably determines that such account is satisfactory. The costs of establishing and maintaining the escrow account shall be borne by Shipper. The escrow bank must be acceptable to Owner. The escrow agreement shall provide for prepayment amounts to be applied against Shipper's obligation under its service agreement(s) with Owner and shall grant Owner a security interest in such amounts as an assurance of future performance. The escrow agreement shall specify the permitted investments of escrowed funds so as to protect principal, and shall include only such investment options as corporations typically use for short-term deposit of their funds. If Owner is required to draw down the funds in escrow, Shipper shall replenish such funds no later than five (5) business days.

8. <u>Assignment</u>.

(a) Prior to the commencement of service pursuant to the Service Agreement, neither Shipper nor Owner may assign any of its rights or obligations under this Precedent Agreement without the prior written consent of the other Party hereto, which consent may be withheld in the other Party's sole discretion; provided, however, that Shipper may assign its rights and obligations under this Precedent Agreement if such assignment is mandated by a valid order of the Florida Public Service Commission and provided further that no such assignment by Shipper shall release Shipper from its obligations hereunder.

(b) Notwithstanding Section 9(a), Owner may, from time to time, without the consent of Shipper, assign this Agreement and the Service Agreement to a lender for collateral security purposes in connection with any financing or the refinancing of the Facility. Shipper agrees to cooperate within reason with the financial institutions that provide financing and/or insurance for the ownership and operation of the Facility (each a "Lender/Insurer") to the extent reasonably required by any such Lender/Insurer in order to underwrite, insure, or re-insure the Project, the operations and the liabilities associated therewith or to protect and give effect to the security interests granted to or for the benefit of the lenders to secure the performance of the obligations of Owner under the agreements and documents executed and delivered in connection with any such financing. Shipper agrees to execute reasonable and customary consenting documents. The provisions of this Paragraph 9(b) shall survive the termination of this Precedent Agreement.

(c) From and after the commencement of service under the Service Agreement, the provisions of the Service Agreement and Owner's FERC Gas Tariff shall govern the assignment of Shipper's rights and obligations under the Service Agreement and the release of all or any portion of Shipper's capacity under the Service Agreement; provided, however, that in the event of an assignment of the Service Agreement by Shipper or a permanent release of all or any portion of Shipper's capacity under the Service Agreement, Shipper's assignee or permanent replacement shipper, as the case may be, shall be required to comply with the creditworthiness provisions of Owner's FERC Gas Tariff as modified by Paragraph 8 of this Precedent Agreement for the remaining term of the Service Agreement.

9. Governing Law. This Precedent Agreement shall be governed by, construed, interpreted, and performed in accordance with the laws of the State of New York, without recourse to any laws governing the conflict of laws.

10. Notice. Except as herein otherwise provided, any notice, request, demand, statement, or bill provided for in this Precedent Agreement, or any notice which any Party desires to give to the others, must be in writing and will be considered duly delivered when mailed by registered or certified mail to the other Party's Post Office address set forth below:

Owner:	MoBay Gas Storage Hub, Inc. 1776 Yorktown, Suite 500 Houston, Texas 77056 Attn: President Fax: (713) 961-2676
Shipper:	Florida Power & Light Company 700 Universe Blvd. Juno Beach, FL 33408 Facsimile: (561) 625-7197 Telephone: (561) 625-7012 Attention: EMT – Gas Operations

or at such other address as any Party designates by written notice. Routine communications, including monthly statements, will be considered duly delivered when mailed by either registered, certified, or ordinary mail.

11. Representations and Warranties. Shipper represents and warrants that (a) it is duly organized and validly existing under the laws of the State of Florida and has all requisite legal

power and authority to execute this Precedent Agreement and carry out the terms, conditions and provisions thereof; (b) this Precedent Agreement constitutes the valid, legal and binding obligation of Shipper, enforceable in accordance with the terms hereof; (c) there are no actions, suits or proceedings pending or, to Shipper's knowledge, threatened against or affecting Shipper before any Court or administrative body that might materially adversely affect the ability of Shipper to meet and carry out its obligations hereunder; and (d) the execution and delivery by Shipper of this Precedent Agreement has been duly authorized by all requisite corporate action.

12. Arbitration. Notwithstanding any provisions to the contrary, the Parties hereto agree that (i) that any dispute hereunder shall be settled pursuant to arbitration under the rules of the American Arbitration Association and (ii) that the situs of the arbitration shall be New York, New York. The provisions of this Paragraph 12 shall survive the termination of this Precedent Agreement.

[redacted]

[redacted]

14. Insurance. Owner shall use commercially reasonable efforts to maintain insurance on Shipper's gas to cover all risks including loss, damage and/or destruction whether do to (i) acts of God, (ii) third party acts or omissions including terrorism or sabotage or (iii) due to any other cause while under Owner's control and possession unless Shipper elects to have Owner reject such insurance as provided in this Paragraph 14. Specifically, Owner agrees to use reasonable efforts to (i) furnish Shipper with proof of insurance coverage, including proof of property coverage in the amount of the Replacement Cost of the stored gas prior to injection of Shipper's gas into the MoBay Storage Project and on an annual basis thereafter, (ii) require its insurance carrier thirty (30) days' prior notice to Shipper of any material change or cancellation of Owners' insurance coverage, (iii) obtain the agreement of its insurer that such insurance shall be endorsed to be primary to any insurance which may be maintained by, or on behalf of Shipper, and (iv) obtain the agreement of its insurer that Shipper shall be named an additional insured and that all applicable policies shall include waivers of subrogation in favor of Shipper. Replacement Cost shall not exceed the volume of stored gas multiplied by $15.00 per Dth. Owner shall have the right to adjust Shipper's Monthly Inventory Insurance Charge for any increases in insurance

costs required to be paid by Owner pursuant to this Paragraph 14. Shipper may elect to reject the insurance coverage to be provided by Owner at any time prior to December 31, 2006 or at any time thereafter upon written notice to Owner as set out hereinafter. Any election by Shipper to reject insurance on Shipper's gas must be made within fifteen (15) days after Owner provides Shipper with notice of the terms of the coverage, or any renewal thereof, and any such rejection shall be irrevocable. Owner shall have no further obligation to maintain such insurance. Shipper shall have the right to audit Owner's insurance costs related to this Paragraph 14. The provisions of this Paragraph 14 shall survive the termination of this Precedent Agreement.

15. Publicity. All press releases or other public communications of any nature whatsoever relating to the transactions contemplated by this Precedent Agreement, and the method of the release thereof, shall be subject to the prior written consent of Owner and Shipper, which consent shall not be unreasonably withheld, conditioned or delayed by any other Party; provided, however, that nothing herein shall prevent a Party from publishing such press releases or other public communications as such Party may consider necessary in order to satisfy such Party's obligations at law or under the rules of any stock or commodities exchange after consultation with the other Parties as is reasonable under the circumstances.

16. Entire Agreement. This Agreement and the exhibits attached hereto contain the entire agreement between the parties and there are no representations, understandings or agreements, oral or written, between the parties which are not included herein.

17. Miscellaneous.

(a) The Parties hereto expressly agree that the execution of this Precedent Agreement and the performance of the services contemplated in this Precedent Agreement are without prejudice to any rights or obligations the Parties have to each other under separate and distinct agreements.

(b) This Precedent Agreement may not be modified or amended unless the Parties execute written agreements to that effect.

(c) Except as expressly provided for in this Precedent Agreement, nothing herein expressed or implied is intended or shall be construed to confer upon or give to any person not a Party hereto any rights, remedies or obligations under or by reason of this Precedent Agreement.

(d) The recitals and representations appearing first above are hereby incorporated in and made a part of this Precedent Agreement.

(e) Each and every provision of this Precedent Agreement shall be considered as prepared through the joint efforts of the Parties and shall not be construed against either Party as a result of the preparation or drafting thereof. It is expressly agreed that no consideration shall be given or presumption made on the basis of who drafted this Precedent Agreement or any specific provision hereof.

(f) Unless the context of this Precedent Agreement requires otherwise, (i) the terms "Paragraph" and "subparagraph" refer to Paragraphs and subparagraphs of this Precedent Agreement, (ii) the terms "hereof," "herein," "hereby," and derivative or similar words refer to the entire agreement, including appendices, (iii) the terms "including" and "include" mean "including without limitation by reason of enumeration."

(g) Owner agrees to provide Shipper on an annual basis audited financials of Falcon Gas Storage Company, Inc. ("Falcon"). *Falcon's fiscal year ends on March 31st and financials* should be available each year approximately one hundred twenty (120) days thereafter.

IN WITNESS WHEREOF, the Parties hereto have caused this Precedent Agreement to be duly executed in several counterparts by their duly authorized officers as of the day and year first above written.

"OWNER"

MOBAY STORAGE HUB, INC.

By:__________________________
Printed Name: ____________________
Title: __________________________

"SHIPPER"

FLORIDA POWER & LIGHT COMPANY

By:___________________________
Printed Name: Terry L. Morrison
Title: Vice President

Exhibits

Exhibit A: Executed Firm Gas Storage Service Agreement

Exhibit A
Executed Firm Gas Storage Service Agreement

Service Agreement No. __________

SERVICE AGREEMENT
(APPLICABLE TO FSS RATE SCHEDULE)

THIS AGREEMENT, made and entered into this ______ day of __________, 2006 by and between MOBAY GAS STORAGE HUB, INC. ("MoBay") and FLORIDA POWER & LIGHT COMPANY ("Shipper"), pursuant to the following recitals and representations.

WITNESSETH: That in consideration of the mutual covenants herein contained, the parties hereto agree as follows:

Section 1. Service to be Rendered. MoBay shall perform and Shipper shall receive service in accordance with the provisions of the effective FSS Rate Schedule and applicable General Terms and Conditions of MoBay's FERC Gas Tariff, Original Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission. MoBay shall store quantities of gas for Shipper up to, but not exceeding, Shipper's Maximum Storage Quantity ("MSQ") as specified in Exhibit A, as the same may be amended from time to time by agreement between Shipper and MoBay, or in accordance with the rules and regulations of the Commission. Service hereunder shall be provided subject to the provisions of Part 284 of the Commission's Regulations.

Section 2. Receipt and Delivery Points. The point(s) at which the gas is tendered by Shipper to MoBay under this contract and the point(s) at which the gas is tendered by MoBay to Shipper under this contract shall be at the point(s) located on MoBay's system designated on Exhibit B hereto.

Section 3. Rates. Shipper shall pay MoBay the charges as described in the FSS Rate Schedule, and specified in Exhibit A to this Service Agreement.

Section 4. Term. Service under this Agreement shall commence as of the in-service date of the MoBay Storage Project and shall continue in full force and effect until the fifteenth anniversary of the in-service date ("Term"). Pre-granted abandonment shall apply upon termination of this Agreement, subject to any right of first refusal Shipper may have under the Commission's regulations and MoBay's Tariff.

Section 5. Notices. Notices to MoBay under this Agreement shall be addressed to it at 1776 Yorktown, Suite 500, Houston, Texas 13501, Attention: Vice President of Marketing, and notices to Shipper shall be addressed to it at 700 Universe Blvd., Juno Beach, FL 33408 Attention: EMT - Gas Operations, until changed by either Party by written notice.

Section 6. Prior Agreements Cancelled. This Service Agreement supersedes and cancels, as of the effective date hereof, the following Service Agreements: N/A

Section 7. Law of Agreement. THE INTERPRETATION AND PERFORMANCE OF THIS AGREEMENT SHALL BE IN ACCORDANCE WITH AND CONTROLLED BY THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO DOCTRINES GOVERNING CHOICE OF LAW.

Section 8. Warehousemen's Lien.

(a) SHIPPER HEREBY ACKNOWLEDGES THAT MOBAY SHALL BE ENTITLED TO, AND MOBAY HEREBY CLAIMS, A LIEN ON ALL GAS RECEIVED BY MOBAY FROM SHIPPER, AND ALL PROCEEDS THEREOF, UPON SUCH RECEIPT BY MOBAY, AS PROVIDED IN SECTION 7-209 OF THE NEW YORK UNIFORM COMMERCIAL CODE WITH THE RIGHTS OF ENFORCEMENT AS PROVIDED THEREIN AND HEREIN. IN NO WAY LIMITING THE FOREGOING, SHIPPER HEREBY

ACKNOWLEDGES THAT MOBAY *SHALL BE ENTITLED TO*, AND MOBAY HEREBY CLAIMS, A LIEN FOR ALL CHARGES FOR STORAGE OR TRANSPORTATION (INCLUDING DEMURRAGE AND TERMINAL CHARGES), INSURANCE, LABOR, OR CHARGES PRESENT OR FUTURE IN RELATION TO THE RECEIVED GAS, AND FOR EXPENSES NECESSARY FOR PRESERVATION OF THE RECEIVED GAS OR REASONABLY INCURRED IN THE SALE THEREOF, PURSUANT TO LAW, AND THAT SUCH LIEN SHALL EXTEND TO LIKE CHARGES AND EXPENSES IN RELATION TO ALL SUCH RECEIVED GAS.

(b) IF DEEMED NECESSARY BY A COURT OF LAW, PURSUANT TO SECTION 7-202(2) OF THE NEW YORK UNIFORM *COMMERCIAL CODE, SHIPPER HEREBY AGREES THAT:*

(i) THIS AGREEMENT, WITH ALL SCHEDULES AND EXHIBITS HERETO, AND ALL OF THE MONTHLY STATEMENTS RENDERED BY MOBAY TO SHIPPER PURSUANT TO THE GENERAL TERMS AND CONDITIONS CONTAINED IN SHIPPER'S TARIFF, SHALL BE DEEMED A "WAREHOUSE RECEIPT" FOR ALL PURPOSES WITH RESPECT TO ARTICLE 7 OF THE NEW YORK UNIFORM COMMERCIAL CODE, REGARDLESS OF WHEN THE GAS STORED PURSUANT TO THE CONTRACT IS RECEIVED,

(ii) THE LOCATION OF THE WAREHOUSE, TO WHOM THE GAS WILL BE DELIVERED, RATE OF STORAGE AND HANDLING CHARGES, AND DESCRIPTION OF THE GOODS ARE AS SET FORTH, RESPECTIVELY, IN OF THE GENERAL TERMS AND CONDITIONS, *APPENDIX B OF THIS AGREEMENT, THE MONTHLY,* STATEMENT (AS DESCRIBED IN SECTION 8.1 OF THE GENERAL TERMS AND CONDITIONS) AND SECTION 1.7 OF THE GENERAL TERMS AND CONDITIONS,

(iii) THE ISSUE DATE OF THE WAREHOUSE *RECEIPT WITH RESPECT TO EACH* RECEIPT OF GAS SHALL BE DEEMED TO BE THE DATE SUCH GAS WAS RECEIVED,

(iv) THE CONSECUTIVE NUMBER OF THE RECEIPT SHALL BE DEEMED BASED ON THE DATES OF RECEIPT WHEN LISTED IN CHRONOLOGICAL ORDER, BEGINNING WITH THE FIRST RECEIPT OF GAS UNDER THE TERMS OF THE CONTRACT, AND

(v) THE SIGNATURE OF MOBAY ON THE CONTRACT SHALL BE DEEMED TO BE THE SIGNATURE OF THE WAREHOUSEMAN.

FLORIDA POWER & LIGHT COMPANY	MOBAY GAS STORAGE HUB, INC.
By____________________	By____________________
Title____________________	Title____________________

Revision No. __________
Control No. __________

Exhibit A to Service Agreement No. __________
Under Rate Schedule FSS
Between
MoBay Gas Storage Hub, Inc. (MoBay)
And
Florida Power & Light Company (Shipper)

Maximum Storage Quantity (MSQ)	6,000,000 Dth
Base Gas Requirement Ratio	Fifty Percent
Base Gas Supplied by Shipper	3,000,000 Dth
Base Gas Supplied by MoBay	N/A Dth
Maximum Daily Withdrawal Quantity (MDWQ)	
Working Gas Inventory:	*MDWQ:*
0 to 1,750,000 Dth:	50,000 Dth per Day
1,750,000 to 2,500,000 Dth:	150,000 Dth per Day
2,500,000 to 6,000,000 Dth:	350,000 Dth per Day
Maximum Daily Injection Quantity (MDIQ)	150,000 Dth per Day
Maximum Hourly Withdrawal Quantity (MHWQ)	__________ Dth per Hour*
Maximum Hourly Injection Quantity (MHIQ)	__________ Dth per Hour*
Monthly Storage Reservation Charge (exclusive of Base Gas Charge and Inventory Insurance Charge)	[redacted] per Dth of MSQ
Monthly Base Gas Charge	$ N/A per Dth of Base Gas Supplied by MoBay
Monthly Inventory Insurance Charge	$0.0125 per Dth of Shipper Gas (MSQ + Base Gas Supplied by Shipper)
Inventory Replacement Value Cap	$15.00 per Dth
Injection Charge	[redacted] per Dth
Withdrawal Charge	[redacted] per Dth
Excess Injection Charge	Negotiable
Excess Withdrawal Charge	Negotiable
Fuel Retention (injected and withdrawn volumes)	One Percent
Authorized Overrun Service Charge	Negotiable

Shipper will ___X___/will not ______ provide the Base Gas required pursuant to the Base Gas Requirement Ratio. If Shipper does not elect to provide the Base Gas within 30 days after the start of construction, then MoBay will provide the Base Gas at Shipper's expense for a Monthly Base Gas Charge. The Monthly Base Gas Charge shall be calculated as the product of the Base Gas cost, multiplied by the Monthly Base Gas Interest Rate. The Monthly Base Gas Interest Rate shall be the Prime Rate of Interest (as published in the Wall Street Journal), plus 2%, divided by 12 ((Prime Rate + 2%)/12). For example, if the cost of the base gas is $7.00 per Dth and the Prime Rate of Interest is 5%, then the Monthly Base Gas Charge will be $0.04 per Dth of Base Gas (($7.00 x (5% + 2%))/12).

MoBay will __X__/will not ______ insure the Replacement Cost of Shipper's gas (at Shipper's expense pursuant to Section 12.2 of the General Terms and Conditions) calculated as the product of the Inventory Insurance Charge, multiplied by the sum of Shipper's MSQ, plus the Base Gas Supplied by Shipper. MoBay shall have the right to adjust Shipper's Monthly Insurance Charge for any increase in insurance costs required to be paid by MoBay; provided however, that Shipper may elect to reject the insurance coverage provided by MoBay at any time upon written notice to MoBay as set out hereinafter. Any election by Shipper to reject insurance on Shipper's gas must be made within fifteen (15) days after MoBay provides notice of the terms of the coverage, or any renewal thereof, and any such rejection shall be irrevocable. Owner shall have no further obligation to maintain insurance on Shipper's gas.

* <u>NOTE 1</u>: The MHIQ shall equal 1/24th of the MDIQ and the MHWQ shall equal 1/24th of the MDWQ unless the Parties specifically designate otherwise on this schedule.

FLORIDA POWER & LIGHT COMPANY	MOBAY GAS STORAGE HUB, INC.
By	By
Its	Its
Date	Date

Revision No. __________
Control No. __________

Exhibit B to Service Agreement No. __________
Under Rate Schedule FSS
Between
MoBay Gas Storage Hub, Inc. (MoBay)
And
Florida Power & Light Company (Shipper)

POINTS OF RECEIPT

1. Gulfstream Pipeline
2. Transco Pipeline, Mobile Bay Lateral
3. Florida Gas Transmission (via Transco Mobile Bay Lateral)
4. GulfSouth Pipeline

For each designated point of receipt, Shipper's Maximum Daily Receipt Quantity (MDRQ) shall be the Shipper's MDIQ. Shipper's aggregate daily nominated receipt quantity shall not exceed Shipper's MDIQ.

POINTS OF DELIVERY

1. Gulfstream Pipeline
2. Transco Pipeline, Mobile Bay Lateral
3. Florida Gas Transmission (via Transco Mobile Bay Lateral)
4. GulfSouth Pipeline

For each designated point of delivery, Shipper's Maximum Daily Delivery Quantity (MDDQ) shall be the Shipper's MDWQ. Shipper's aggregate daily nominated delivery quantity shall not exceed Shipper's MDWQ.

Receipt and Delivery quantities shall be subject to applicable General Terms and Conditions of MoBay's FERC Gas Tariff, Original Volume No. 1 ("Tariff"), on file with the Federal Energy Regulatory Commission ("Commission"), as the same may be amended or superseded in accordance with the rules and regulations of the Commission.

CONFIDENTIAL
Florida Power and Light Company
Attachment 3
Page 1 of 1

A	B	C	D	E	F
Storage Facilities	Firm Capacity	Withdrawal (MMBtu/day)	Injection (MMBtu/day)	Reservation Charge ($/MMBtu per month)	Annual Storage Cost per Bcf
Bay Gas	2 Bcf	325,000	75,000	[redacted]	[redacted]
MoBay/Falcon	6 Bcf	350,000	150,000	[redacted]	[redacted]

SCHEDULE B-18 | FUEL INVENTORY BY PLANT | Attachment 4
Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO. 050045-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year, and the two preceding years. Include Natural Gas even though no inventory is carried. (Give Units in Barrels, Tons, or MCF)

Type of Data Shown:
X Projected Test Year Ended 12/31/2006
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: William L. Yeager

LINE NO.	(1) NAME OF PLANT FUEL TYPE	(2) MONTH	(3) BEGINNING BALANCE UNITS/	(4) BEGINNING BALANCE ($000)/	(5) BEGINNING BALANCE $/UNIT	(6) RECEIPTS UNITS/	(7) RECEIPTS ($000)/	(8) RECEIPTS $/UNIT	(9) FUEL ISSUED TO GENERATION UNITS/	(10) FUEL ISSUED TO GENERATION ($000)/	(11) FUEL ISSUED TO GENERATION $/UNIT	(12) FUEL ISSUED(OTHER) UNITS/	(13) FUEL ISSUED(OTHER) ($000)/	(14) FUEL ISSUED(OTHER) $/UNIT	(15) INVENTORY ADJUSTMENTS UNITS/	(16) INVENTORY ADJUSTMENTS ($000)/	(17) INVENTORY ADJUSTMENTS $/UNIT	(18) ENDING BALANCE UNITS/	(19) ENDING BALANCE ($000)/	(20) ENDING BALANCE $/UNIT	(21) 13 MONTH AVERAGE UNITS/	(22) 13 MONTH AVERAGE ($000)/ (See Note 1)	(23) 13 MONTH AVERAGE $/UNIT
1	HEAVY OIL BBL																						
2	RIVIERA(PRV)	Jan-06	250,000	7,699	30.80	209,043	6,490	31.05	159,043	4,916	30.91							300,000	9,273	30.91	260,846	8,107	31.84
3		Feb-06	300,000	9,273	30.91	171,450	5,214	30.41	171,450	5,269	30.73							300,000	9,218	30.73	257,692	8,178	31.74
4		Mar-06	300,000	9,218	30.73	200,361	5,968	29.79	200,361	6,081	30.35							300,001	9,105	30.35	261,538	8,247	31.59
5		Apr-06	300,001	9,105	30.35	167,450	4,990	29.80	167,450	5,049	30.15							300,000	9,046	30.15	265,385	8,321	31.35
6		May-06	300,000	9,046	30.15	328,487	9,899	30.32	328,487	9,873	30.24							300,002	9,072	30.24	269,231	8,403	31.21
7		Jun-06	300,002	9,072	30.24	329,122	10,101	30.69	329,122	10,031	30.48							300,003	9,143	30.48	273,077	8,491	31.10
8		Jul-06	300,003	9,143	30.48	366,212	11,223	30.65	366,212	11,195	30.57							300,005	9,171	30.57	276,924	8,580	30.98
9		Aug-06	300,005	9,171	30.57	345,773	10,568	30.56	345,773	10,569	30.57							300,003	9,170	30.57	280,770	8,667	30.87
10		Sep-06	300,003	9,170	30.57	336,153	10,149	30.19	336,153	10,208	30.37							300,003	9,111	30.37	284,617	8,748	30.74
11		Oct-06	300,003	9,111	30.37	279,545	8,237	29.47	279,545	8,368	29.93							300,002	8,980	29.93	288,463	8,828	30.59
12		Nov-06	300,002	8,980	29.93	117,106	3,415	29.16	117,106	3,480	29.72							300,000	8,915	29.72	292,309	8,902	30.46
13		Dec-06	300,000	8,915	29.72	160,599	4,592	28.59	160,599	4,710	29.32							300,000	8,797	29.32	296,155	8,977	30.31
14																							
15	SANFORD (PSN)	Jan-06	80,000	2,455	30.69	70,636	2,366	33.50	636	20	31.99							150,000	4,800	32.00	112,069	3,275	29.22
16		Feb-06	150,000	4,800	32.00	24	1	41.67	24	1	31.71							150,000	4,800	32.00	111,899	3,304	29.51
17		Mar-06	150,000	4,800	32.00	1,618	52	32.24	1,613	52	32.01							150,000	4,801	32.00	111,541	3,345	29.99
18		Apr-06	150,000	4,801	32.00	3,282	106	32.30	3,282	105	32.01							150,000	4,801	32.01	111,639	3,387	30.37
19		May-06	150,000	4,801	32.01	7,289	239	32.79	7,289	234	32.04							150,000	4,807	32.04	112,283	3,450	30.74
20		Jun-06	150,000	4,807	32.04	4,728	157	33.21	4,728	152	32.08							150,000	4,812	32.08	114,732	3,564	31.06
21		Jul-06	150,000	4,812	32.06	10,812	358	33.11	10,812	348	32.15							150,000	4,822	32.15	118,226	3,707	31.36
22		Aug-06	150,000	4,822	32.15	12,294	406	33.02	12,293	396	32.21							150,000	4,832	32.21	123,077	3,889	31.60
23		Sep-06	150,000	4,832	32.21	10,202	333	32.64	10,202	329	32.24							150,000	4,836	32.24	128,462	4,082	31.77
24		Oct-06	150,000	4,836	32.24	2,505	80	31.96	2,503	81	32.24							150,000	4,835	32.24	133,846	4,269	31.90
25		Nov-06	150,000	4,835	32.24	289	9	31.14	288	9	32.23							150,000	4,835	32.23	139,231	4,459	31.98
26		Dec-06	150,000	4,835	32.23	0	0	0.00	0	0	0.00							150,000	4,835	32.23	144,615	4,638	32.06
27																							
28	PORT EVERGLADES(PPE)	Jan-06	352,401	11,060	31.38	277,173	8,597	31.02	129,575	4,046	31.22							500,000	15,611	31.22	411,723	13,153	31.97
29		Feb-06	500,000	15,611	31.22	211,818	6,436	30.38	211,818	6,560	30.97							499,999	15,488	30.97	427,108	13,589	31.82
30		Mar-06	499,999	15,488	30.97	256,286	7,626	29.75	256,286	7,831	30.56							499,999	15,280	30.56	442,492	14,002	31.64
31		Apr-06	499,999	15,280	30.56	290,235	8,640	29.77	290,236	8,785	30.27							499,999	15,135	30.27	454,031	14,294	31.48
32		May-06	499,999	15,135	30.27	712,052	21,567	30.29	712,062	21,562	30.28							500,002	15,141	30.28	457,877	14,363	31.36
33		Jun-06	500,002	15,141	30.28	712,479	21,845	30.66	712,479	21,734	30.50							500,003	15,252	30.50	461,723	14,421	31.23
34		Jul-06	500,003	15,252	30.50	827,449	25,331	30.61	827,449	25,287	30.57							500,010	15,296	30.57	465,570	14,489	31.12
35		Aug-06	500,010	15,296	30.57	776,405	23,707	30.53	776,408	23,718	30.55							500,006	15,274	30.55	469,417	14,551	31.00
36		Sep-06	500,006	15,274	30.55	757,580	22,850	30.16	757,580	22,967	30.32							500,004	15,158	30.32	473,263	14,603	30.86
37		Oct-06	500,004	15,158	30.32	596,029	17,644	29.43	596,029	17,783	29.84							500,003	14,918	29.84	477,110	14,643	30.69
38		Nov-06	500,003	14,918	29.84	139,316	4,059	29.13	139,318	4,135	29.68							500,000	14,842	29.68	480,956	14,692	30.55
39		Dec-06	500,000	14,842	29.68	163,701	4,575	28.68	163,701	4,814	29.41							500,000	14,703	29.41	484,646	14,857	30.41
40																							
41	CAPE CANAVERAL(PCC)	Jan-06	305,000	9,402	30.83	255,366	7,902	30.94	110,366	3,408	30.88							450,000	13,896	30.88	339,231	11,576	35.01
42		Feb-06	450,000	13,896	30.88	232,278	7,039	30.30	232,278	7,127	30.68							450,000	13,808	30.68	350,385	11,101	31.68
43		Mar-06	450,000	13,808	30.68	267,475	7,938	29.68	267,475	8,107	30.31							450,000	13,639	30.31	361,538	11,360	31.42
44		Apr-06	450,000	13,639	30.31	278,454	8,269	29.70	278,454	8,374	30.07							450,000	13,534	30.07	365,846	11,566	31.28
45		May-06	450,000	13,534	30.07	159,653	4,824	30.22	159,653	4,807	30.11							450,000	13,550	30.11	376,154	11,706	31.12
46		Jun-06	450,000	13,550	30.11	194,467	5,948	30.59	194,467	5,885	30.26							450,000	13,614	30.25	389,462	11,882	30.99
47		Jul-06	450,000	13,614	30.26	244,410	7,484	30.64	244,410	7,419	30.36							450,000	13,669	30.36	390,769	12,059	30.86
48		Aug-06	450,000	13,658	30.36	201,481	6,137	30.46	201,481	6,122	30.39							450,000	13,674	30.39	398,077	12,235	30.74
49		Sep-06	450,000	13,674	30.39	180,018	5,416	30.09	180,018	5,455	30.30							450,000	13,635	30.30	405,885	12,407	30.60
50		Oct-06	450,000	13,635	30.30	195,663	5,744	29.36	195,663	5,875	30.01							450,000	13,507	30.01	419,538	12,595	30.43
51		Nov-06	450,000	13,507	30.01	214,436	6,231	29.06	214,436	6,370	29.71							450,000	13,368	29.71	427,692	12,985	30.36
52		Dec-06	450,000	13,368	29.71	109,578	3,121	28.48	109,578	3,228	29.47							450,000	13,260	29.47	438,846	13,273	30.24
53																							
54	MANATEE(PMT)	Jan-06	900,000	28,101	31.22	56,078	1,734	30.92	56,078	1,750	31.21							900,000	28,085	31.21	925,077	28,482	31.84
55		Feb-06	900,000	28,085	31.21	16,469	498	30.28	16,469	513	31.19							900,000	28,070	31.19	930,768	28,607	31.81
56		Mar-06	900,000	28,070	31.19	285,586	8,478	29.68	285,586	8,811	30.82							900,000	27,737	30.82	938,461	28,719	31.67
57		Apr-06	900,000	27,737	30.82	239,787	7,114	29.67	239,787	7,332	30.58							900,000	27,519	30.58	948,164	28,850	31.55
58		May-06	900,000	27,519	30.58	709,191	21,408	30.19	709,191	21,563	30.41							900,000	27,365	30.41	953,846	28,896	31.46
59		Jun-06	900,000	27,365	30.41	495,270	15,135	30.56	495,270	15,088	30.46							900,000	27,414	30.46	953,846	28,903	31.35
60		Jul-06	900,000	27,414	30.46	905,054	27,616	30.51	905,054	27,581	30.49							899,998	27,487	30.49	946,154	28,556	31.24
61		Aug-06	899,998	27,487	30.49	827,296	28,218	30.43	827,295	28,244	30.46							899,996	27,410	30.46	930,769	28,256	31.11
62		Sep-06	899,996	27,410	30.46	862,026	26,618	30.06	862,029	26,802	30.25							899,997	27,225	30.25	915,364	28,336	30.96
63		Oct-06	899,997	27,225	30.25	474,674	13,920	29.33	474,674	14,207	29.94							900,000	26,942	29.94	907,692	27,951	30.79
64		Nov-06	900,000	26,942	29.94	201,629	5,851	29.03	201,529	6,000	29.77							900,000	26,793	29.77	899,999	27,576	30.64
65		Dec-06	900,000	26,793	29.77	177,997	5,065	28.46	177,997	5,260	29.55							900,000	26,598	29.55	895,999	27,439	30.48
66																							
67	MARTIN(PMR)	Jan-06	540,000	18,637	31.81	506,472	15,674	31.01	146,472	4,496	30.81							900,000	27,815	30.81	857,693	19,066	31.96
68		Feb-06	900,000	27,815	30.91	300,448	9,125	30.37	300,448	9,245	30.77							900,000	27,685	30.77	595,385	18,842	31.65
69		Mar-06	900,000	27,685	30.77	206,781	6,210	29.74	206,781	6,364	30.58							900,000	27,521	30.58	623,077	19,592	31.44
70		Apr-06	900,000	27,521	30.58	255,554	7,606	29.76	255,554	7,771	30.40							900,000	27,358	30.40	650,770	20,345	31.26
71		May-06	900,000	27,358	30.40	719,373	21,782	30.28	719,373	21,829	30.34							899,998	27,310	30.34	678,462	21,121	31.13
72		Jun-06	899,998	27,310	30.34	715,499	21,529	30.55	715,499	21,307	30.48							899,999	27,432	30.48	706,154	21,907	31.02
73		Jul-06	899,999	27,432	30.48	810,713	24,611	30.80	810,713	24,756	30.54							899,997	27,486	30.54	733,848	22,691	30.92
74		Aug-06	899,997	27,486	30.54	786,832	23,407	30.52	786,832	23,413	30.55							899,999	27,479	30.53	761,538	23,469	30.82
75		Sep-06	899,998	27,479	30.53	749,912	22,811	30.15	749,912	22,767	30.36							899,998	27,323	30.36	789,230	24,283	30.71
76		Oct-06	899,998	27,323	30.36	661,274	19,458	29.43	661,274	19,614	29.66							899,998	26,967	29.96	816,922	24,961	30.58
77		Nov-06	899,998	26,967	29.96	369,371	10,780	29.12	369,471	10,980	29.72							900,000	26,747	29.72	844,614	25,734	30.47
78		Dec-06	900,000	26,747	29.72	385,512	11,006	28.56	385,512	11,322	29.37							900,000	26,432	29.37	872,307	26,477	30.35
79																							
80																							
81																							
82																							
83																							
84																							
85																							
86	Note 1 - Applicable only to system fuel inventory balances.																						

Supporting Schedules: | Recap Schedules:

SCHEDULE B-18

FUEL INVENTORY BY PLANT

FLORIDA PUBLIC SERVICE COMMISSION

Attachment 4
Page 3 of 3

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO. 050045-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type for the test year, and the two preceding years. Include Natural Gas even though no inventory is carried. (Give Units in Barrels, Tons, or MCF)

Type of Data Shown:
X Projected Test Year Ended 12/31/2006
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: William L. Yeager

LINE NO.	(1) NAME OF PLANT	FUEL TYPE	(2) MONTH	(3) BEGINNING BALANCE UNITS/	(4) ($000)/	(5) $/UNIT	(6) RECEIPTS UNITS/	(7) ($000)/	(8) $/UNIT	(9) FUEL ISSUED TO GENERATION UNITS/	(10) ($000)/	(11) $/UNIT	(12) FUEL ISSUED(OTHER) UNITS/	(13) ($000)/	(14) $/UNIT	(15) INVENTORY ADJUSTMENTS UNITS/	(16) ($000)/	(17) $/UNIT	(18) ENDING BALANCE UNITS/	(19) ($000)/	(20) $/UNIT	(21) 13 MONTH AVERAGE UNITS/	(22) ($000)/	(23) $/UNIT
																							(See Note 1)	
1	LAUDERDALE(FLG)		Jan-06	218,934	8,725	39.85	0	0	0.00	5	0	39.80							218,929	8,725	39.85	220,759	8,797	39.85
2			Feb-06	218,929	8,725	39.85	0	0	0.00	0	0	0.00							218,929	8,725	39.85	220,470	8,768	39.86
3			Mar-06	218,929	8,725	39.85	0	0	0.00	0	0	0.00							218,929	8,725	39.85	220,202	8,775	39.85
4			Apr-06	218,929	8,725	39.85	0	0	0.00	0	0	0.00							218,928	8,725	39.85	219,953	8,765	39.85
5			May-06	218,928	8,725	39.85	0	0	0.00	2,267	90	39.86							216,661	8,634	39.85	219,634	8,749	39.85
6			Jun-06	216,661	8,634	39.85	0	0	0.00	3,544	141	39.85							213,117	8,493	39.85	218,889	8,723	39.85
7			Jul-06	213,117	8,493	39.85	0	0	0.00	5,698	226	39.85							208,419	8,107	39.85	217,518	8,668	39.85
8			Aug-06	208,419	8,107	39.85	10,283	391	37.99	13,712	546	39.76							200,000	7,952	39.76	215,899	8,603	39.85
9			Sep-06	200,000	7,952	39.76	6,245	239	38.27	6,245	248	39.72							200,000	7,943	39.72	214,814	8,537	39.84
10			Oct-06	200,000	7,943	39.72	33,536	1,298	38.65	33,536	1,327	39.56							200,000	7,913	39.56	212,758	8,471	39.81
11			Nov-06	200,000	7,918	39.56	0	0	0.00	0	0	0.00							200,000	7,918	39.56	211,221	8,406	39.79
12			Dec-06	200,000	7,918	39.56	0	0	0.00	0	0	0.00							200,000	7,913	39.56	209,834	8,346	39.77
13																								
14	COAL																							
15																								
16	SJRPP	(TONS)																						
17	(COAL & PET COKE)		Jan-06	45,218	1,771	39.16	67,221	2,659	39.70	67,221	2,646	39.36							45,218	1,794	39.67	46,609	1,823	39.10
18			Feb-06	45,218	1,794	39.67	57,320	2,276	39.71	57,320	2,267	39.55							45,217	1,802	39.86	46,609	1,824	39.12
19			Mar-06	45,217	1,802	39.86	34,537	1,371	39.70	34,537	1,366	39.52							45,217	1,806	39.93	46,609	1,826	39.19
20			Apr-06	45,217	1,806	39.93	38,498	1,533	39.82	38,498	1,529	39.71							45,217	1,810	40.03	46,609	1,830	39.26
21			May-06	45,217	1,810	40.03	66,853	2,662	39.82	66,853	2,659	39.78							45,218	1,813	40.09	46,609	1,834	39.35
22			Jun-06	45,218	1,813	40.09	69,230	2,757	39.82	64,708	2,576	39.80							49,740	1,994	40.09	46,957	1,852	39.44
23			Jul-06	49,740	1,994	40.09	66,462	2,656	39.96	66,462	2,651	39.88							49,740	1,998	40.18	46,957	1,857	39.55
24			Aug-06	49,740	1,998	40.18	66,882	2,672	39.96	66,882	2,670	39.92							49,740	2,000	40.21	46,957	1,862	39.65
25			Sep-06	49,740	2,000	40.21	64,778	2,587	39.94	64,778	2,587	39.93							49,740	2,001	40.23	46,957	1,867	39.75
26			Oct-06	49,740	2,001	40.23	61,947	2,482	40.07	66,469	2,659	40.01							45,218	1,824	40.33	46,609	1,856	39.86
27			Nov-06	45,218	1,824	40.33	65,625	2,629	40.06	65,625	2,628	40.04							45,218	1,826	40.37	46,609	1,862	39.95
28			Dec-06	45,218	1,826	40.37	67,808	2,717	40.07	67,808	2,716	40.06							45,218	1,826	40.38	46,609	1,866	40.04
29	SCHERER	(MMBTU, see Note 2)	Jan-06	2,905,543	4,629	1.59	3,916,028	6,538	1.67	3,916,028	6,410	1.64							2,905,543	4,756	1.64	2,994,941	4,776	1.59
30																								
31			Feb-06	2,905,543	4,756	1.64	3,547,636	5,923	1.67	3,547,636	5,871	1.65							2,905,543	4,808	1.65	2,994,939	4,798	1.60
32			Mar-06	2,905,543	4,808	1.65	3,971,275	6,630	1.67	3,971,275	6,605	1.66							2,905,543	4,833	1.66	2,994,938	4,809	1.61
33			Apr-06	2,905,543	4,833	1.66	3,828,736	6,392	1.67	3,828,768	6,342	1.67							2,905,560	4,849	1.67	2,994,935	4,826	1.61
34			May-06	2,905,560	4,849	1.67	3,918,965	6,543	1.67	3,918,965	6,534	1.67							2,905,560	4,847	1.67	2,994,941	4,843	1.62
35			Jun-06	2,905,560	4,847	1.67	4,087,590	6,841	1.67	3,607,036	6,364	1.67							3,196,113	5,334	1.67	3,017,293	4,898	1.62
36			Jul-06	3,196,113	5,334	1.67	3,903,393	6,517	1.67	3,903,393	6,516	1.67							3,196,113	5,336	1.67	3,017,296	4,917	1.63
37			Aug-06	3,196,113	5,336	1.67	3,918,880	6,542	1.67	3,918,880	6,542	1.67							3,196,113	5,335	1.67	3,017,299	4,935	1.64
38			Sep-06	3,196,113	5,335	1.67	3,791,958	6,329	1.67	3,791,958	6,329	1.67							3,196,113	5,336	1.67	3,017,302	4,954	1.64
39			Oct-06	3,196,113	5,336	1.67	3,596,673	6,005	1.67	3,886,225	6,488	1.67							2,905,560	4,851	1.67	2,994,954	4,936	1.65
40			Nov-06	2,905,560	4,851	1.67	3,806,688	6,356	1.67	3,806,688	6,355	1.67							2,905,543	4,851	1.67	2,994,955	4,953	1.65
41			Dec-06	2,905,543	4,851	1.67	3,934,315	6,568	1.67	3,934,315	6,568	1.67							2,905,543	4,851	1.67	2,994,954	4,970	1.66
42	NATURAL GAS	(MMBTU, see Note 2)	Jan-06				31,200,457	204,960	6.57	31,200,457	204,960	6.57												
43																								
44			Feb-06				27,698,640	180,629	6.52	27,698,640	180,629	6.52												
45			Mar-06				32,782,501	207,221	6.32	32,782,501	207,221	6.32												
46			Apr-06				32,106,787	183,806	5.72	32,106,787	183,806	5.72												
47			May-06				36,064,466	201,341	5.58	36,064,466	201,341	5.58												
48			Jun-06				37,051,212	207,208	5.59	37,051,212	207,208	5.59												
49			Jul-06				40,828,358	227,983	5.61	40,828,358	227,983	5.61												
50			Aug-06				40,487,914	227,996	5.63	40,487,914	227,996	5.63												
51			Sep-06				36,179,292	202,634	5.60	36,179,292	202,634	5.60												
52			Oct-06				38,893,107	217,450	5.59	38,893,107	217,450	5.59												
53			Nov-06				30,866,867	177,416	5.75	30,866,867	177,416	5.75												
54			Dec-06				32,804,498	194,200	5.92	32,804,498	194,200	5.92												
55																								
56																								
57																								
58																								
59																								
60																								
61	Note 1 - Applicable only to system fuel inventory balances.																							
62	Note 2 - FPL measures these items in MMBTU units.																							
63																								

Supporting Schedules:

Recap Schedules:

CONFIDENTIAL

	A	B	C	D	E	F	G
1	[redacted]						
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Docket No. 060001-EI
Gerard J. Yupp
Exhibit GJY- 4
Total Annual Costs - SESH Pipeline Project

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 5
Company/ FPL
Witness: G. Yupp (GJY-4)
Date: 11/06-08/06

Curriculum Vitae

PATRICIA W. MERCHANT, C.P.A.

Office of Public Counsel
Room 812, 111 West Madison Street
Tallahassee, Florida 32399-1400

Phone: 850-487-8245
Fax: 850-488-4491
E-mail: merchant.tricia@leg.state.fl.us

Professional Experience:

March, 2005 to Present

Office of Public Counsel – Senior Legislative Analyst

In my current position, I perform financial and accounting analysis and reviews, and provide testimony, as required, involving utility filings before the Florida Public Service Commission (or other jurisdictions) as an advocate for the Citizens of the State of Florida.

1981 to February, 2005 - Florida Public Service Commission

2000 to February, 2005

Public Utilities Supervisor – File and Suspend Rate Case Section, Bureau of Rate Filings, Division of Economic Regulation

In this capacity I was responsible for the supervision of 5 to 8 regulatory professionals. This section was responsible for the financial, accounting, engineering and rate review and evaluation of rate proceedings for Class A and B water and wastewater utilities, as well as electric and gas utilities regulated by the Commission. The types of cases included file and suspend rate cases, limited proceedings, overearning investigations, annual report reviews, service availability and tariff filings, rulemaking, and customer complaints. The analysts in this section reviewed utility filings, requested and reviewed Commission staff audits, and generated and analyzed discovery requests. Each analyst coordinated and prepared staff recommendations to the Commission for agenda conferences. As a supervisor, I reviewed the analytical work and edited the written documents of all analysts in this section for proper regulatory theory, grammar and accuracy. I also made presentations to customer groups at Commission staff customer meetings for the rate proceedings to which I was assigned. Staff recommendations were presented at agenda conferences with an introduction of each item, providing a response to comments raised by other parties and addressing the questions of Commissioners. The section also prepared and presented testimony, and assisted in the preparation of cross-examination questions for depositions and formal hearings. In addition to other duties, I provided training in regulatory accounting for new staff in my section as well as training on regulatory and accounting issues for other analysts at the Commission.

1989 – 2000

Regulatory Analyst Supervisor, Accounting Section, Bureau of Economic Regulation, Division of Water and Wastewater

I supervised 5-7 regulatory accounting analysts. This section performed the same job activities as above specifically for the larger Commission regulated Class A and B water and wastewater companies.

1983 - 1989

Regulatory Analyst – Accounting Bureau, Division of Water and Wastewater

As an accounting analyst, I performed the same job activities as described above for water and wastewater companies in a non-supervisory role.

1981 – 1983

Public Utilities Auditor, Division of Auditing and Financial Analysis

As an auditor in the Tallahassee district of the Commission, I performed financial and accounting audits of electric, gas, telephone, water and wastewater utilities under the Commission's jurisdiction.

Education and Professional Licenses

1981 Bachelor of Science with a major in accounting from Florida State University

1983 Received a Certified Public Accountant license in Florida

Attachments

1 List of Cases in which Testimony was Submitted

2 List of Analytical and Supervisory Rate Case Work Performed at the Public Service Commission

Patricia W. Merchant
Submitted Testimony in the Following Cases:

Dockets Before the Florida Public Service Commission:

991643-SU	Application for Increase in Wastewater Rates in Seven Springs System in Pasco County by Aloha Utilities, Inc.
971663-WS	Application of Florida Cities Water Company, Inc. for a limited proceeding to recover environmental litigation costs.
940847-WS	Application of Ortega Utility Company for increased water and wastewater rates.
911082-WS	Water and Wastewater Rule Revisions to Chapter 25-30, Florida Administrative Code.
881030-WU	Investigation of Sunshine Utilities of Central Florida rates for possible over earnings.
850151-WS	Application of Marco Island Utilities, Inc. for increased water and wastewater rates.
850031-WS	Application of Orange/Osceola Utilities, Inc. for increased water and wastewater rates in Osceola County
840047-WS	Application of Poinciana Utilities, Inc. for increased water and wastewater rates

Cases Before the Division of Administrative Hearings:

97-2485RU	Aloha Utilities, Inc., and Florida Waterworks Association, Inc., Petitioners, vs. Public Service Commission, Respondents, and Citizens of the State of Florida, Office of Public Counsel, Intervenors

Gulf Power Company Rate Case MFRs – Docket No. 010949-EI – Schedule of Fuel Inventory

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 060362-EI Exhibit No. 7
Company/ OPC
Witness: P. Merchant (PWM-2)
Date: 11/06-08/06

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type by month for the test year, and the prior year if the test year is projected. Include Natural Gas even though no inventory is carried. (Give Units in Barrels, Tons, or MMCF.)

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Year Ended 12/31/00
Witness: R. G. Moore, R. R. Labrato

Fuel Type	Month	Beginning Balance			Receipts			Fuel Issued to Generation		
		Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit
Plants: Crist, Smith CC, Bay Gas Storage										
Natural Gas (Mmcf)										
1	May 02	0	0	0.000	34	120	3,529.412	34	120	3,529.412
2	Jun 02	0	0	0.000	3,482	13,023	3,740.092	2,654	10,949	4,125.471
3	Jul 02	828	2,074	2,504.831	2,751	15,836	5,756.452	2,751	15,836	5,756.452
4	Aug 02	828	2,582	3,118.357	2,992	17,110	5,718.583	2,992	17,110	5,718.583
5	Sep 02	828	3,094	3,736.715	2,099	8,981	4,278.704	2,099	8,981	4,278.704
6	Oct 02	828	2,069	2,498.792	1,369	6,329	4,623.083	1,369	6,329	4,623.083
7	Nov 02	828	1,809	2,184.783	935	5,388	5,762.567	935	5,388	5,762.567
8	Dec 02	828	2,397	2,894.928	432	3,480	8,055.556	432	3,480	8,055.556
9	Jan 03	828	2,456	2,966.184	877	5,614	6,401.368	877	5,614	6,401.368
10	Feb 03	828	2,813	3,397.343	1,365	7,177	5,257.875	1,365	7,177	5,257.875
11	Mar 03	828	2,567	3,100.242	1,287	6,853	5,324.786	1,287	6,853	5,324.786
12	Apr 03	828	2,069	2,498.792	1,660	7,409	4,463.253	1,660	7,409	4,463.253
13	May 03	828	1,987	2,399.759	1,316	6,192	4,705.167	1,316	6,192	4,705.167
14	Total	9,112	25,917		20,599	103,512		19,771	101,438	
15	13 Month Average	701	1,994	2845.738	1,585	7,962	5,023.344	1,521	7,803	5,130.178

** NOTE: The monthly value of gas inventory is the mathematic product of a desired fixed volume (60% of capacity) times the projected forecast price of gas for a given month. Hence, the monthly inventory adjustment simply accounts for the assumed change in the monthly price projection.

Supporting Schedules: B-17b Recap Schedules:

162

Docket No. 060001-EI
Patricia W. Merchant
Exhibit ___ (PWM-2)
Page 2 of 3

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide conventional fuel account balances in dollars and quantities for each fuel type by month for the test year, and the prior year if the test year is projected. Include Natural Gas even though no inventory is carried. (Give Units in Barrels, Tons, or MMCF.)

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Year Ended 12/31/00
Witness: R. G. Moore, R. R. Labrato

Plants: Crist, Smith, Smith CC, Bay Gas Storage
Natural Gas (Mmcf)

		Fuel Issued (Other)			Inventory Adjustments			Ending Balance			***In-Transit	End. Bal.
		Units	($000)	$/Unit	Units	($000)	$/Unit	Units	($000)	$/Unit	($000)	($000)
1	May 02	0	0	0.000	0	0	0.000	0	0	0.000	0	0
2	Jun 02	0	0	0.000	0	0	0.000	828	2,074	2,504.831	0	2,074
3	Jul 02	0	0	0.000	0	508	0.000	828	2,582	3,118.357	0	2,582
4	Aug 02	0	0	0.000	0	512	0.000	828	3,094	3,736.715	0	3,094
5	Sep 02	0	0	0.000	0	(1,025)	0.000	828	2,069	2,498.792	0	2,069
6	Oct 02	0	0	0.000	0	(260)	0.000	828	1,809	2,184.783	0	1,809
7	Nov 02	0	0	0.000	0	588	0.000	828	2,397	2,894.928	0	2,397
8	Dec 02	0	0	0.000	0	59	0.000	828	2,456	2,966.184	0	2,456
9	Jan 03	0	0	0.000	0	357	0.000	828	2,813	3,397.343	0	2,813
10	Feb 03	0	0	0.000	0	(246)	0.000	828	2,567	3,100.242	0	2,567
11	Mar 03	0	0	0.000	0	(498)	0.000	828	2,069	2,498.792	0	2,069
12	Apr 03	0	0	0.000	0	(82)	0.000	828	1,987	2,399.759	0	1,987
13	May 03	0	0	0.000	0	(69)	0.000	828	1,918	2,316.425	0	1,918
14	Total	0	0		0	(156)		9,936	27,835		0	27,835
15	13 Month Average	0	0	0.000	0	(18)	0.000	764	2,141	2,802.356	0	2,141

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