BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010001-EI

In the Matter of

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE AND
GENERATING PERFORMANCE
INCENTIVE FACTOR
________________________________/

ELECTRIC VERSIONS OF THIS TRANSCRIPT ARE
A CONVENIENCE COPY ONLY AND ARE NOT
THE OFFICIAL TRANSCRIPT OF THE HEARING,
THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

VOLUME 3

Pages 232 through 396

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN E. LEON JACOBS, JR.
COMMISSIONER J. TERRY DEASON
COMMISSIONER LILA A. JABER
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER MICHAEL A. PALECKI

DATE: Wednesday, November 21, 2001

TIME: Commenced at 8:35 a.m.

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

REPORTED BY: TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

NAME:	PAGE NO.
W. LYNN BROWN (Rebuttal	
Direct Examination by Mr. Beasley	235
Prefiled Rebuttal Testimony Inserted	236
Cross Examination by Mr. McWhirter	248
Redirect Examination by Mr. Beasley	271
J. DENISE JORDAN (Rebuttal)	
Direct Examination by Mr. Beasley	272
Prefiled Rebuttal Testimony Inserted	273
Cross Examination by Mr. McWhirter	285
Cross Examination by Mr. Keating	308
Redirect Examination by Mr.Beasley	310
JAVIER PORTUONDO	
Direct Examination by Mr. McGee	313
Prefiled Direct Testimonies Inserted	316
Cross Examination by Mr. McWhirter	350
Cross Examination by Mr. Keating	354
TERRY A. DAVIS	
Stipulated Prefiled Direct Testimony Inserted	360
MICHAEL F. OAKS	
Stipulated Prefiled Direct Testimony Inserted	382

EXHIBITS

NUMBER:		ID.	ADMTD.
11	JDJ-1	310	311
12	JP-1, Parts A, B and C	314	358
13	TAD-1, TAD-2 and TAD-3	359	359
14	MFO-1 and MFO-2	381	

CERTIFICATE OF REPORTER 395

P R O C E E D I N G S

(Transcript continues in sequence from Volume 2.)

CHAIRMAN JACOBS: Good morning. We're here live and in living color. I believe, Mr. Beasley, your witness is up for rebuttal.

MR. BEASLEY: Yes, sir. I'd like to call Mr. Lynn Brown for rebuttal.

W. LYNN BROWN

was called as a rebuttal witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Brown, did you prepare and cause to be submitted in this proceeding a document entitled, "Prepared Rebuttal Testimony of W. Lynn Brown" dated October 26, 2001?

A Yes, I did.

Q If I were to ask you the questions contained in that rebuttal testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I'd ask that Mr. Brown's rebuttal testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Mr. Brown's testimony is entered into the record as though read.

MR. BEASLEY: Thank you.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

W. LYNN BROWN

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

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Wholesale Marketing and Sales.

Q. Are you the same W. Lynn Brown who filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses certain deficiencies in the prepared direct testimony of Brian Collins and Jeffrey Pollock, consultants testifying on behalf of the Florida Industrial Power Users Group ("FIPUG").

Q. Please provide an overall description of Mr. Collins' direct testimony.

A. Mr. Collins purports to perform an "audit" of Tampa Electric's management of its long-term wholesale power contracts. His "audit" is based on a deliberate sample that captures a worst case scenario represented by 63 hours. Mr. Collins next assumes this worse case scenario would have been the norm during the entire three-year "audit" period of 1999 through 2001. He then proceeds to rely on his "audit" as the basis for reaching three conclusions. To reach these conclusions, Mr. Collins makes incorrect assumptions and assertions by misapplying and misusing operating data.

<u>FIPUG's "Findings"</u>

Q. Please comment on Mr. Collins' first conclusion that Tampa Electric has been inappropriately allocating more expensive replacement power solely to retail customers while simultaneously providing low-cost native generation to wholesale customers.

A. Mr. Collins' first conclusion is the result of his "findings" that "wholesale customers receive the benefit of TECO's lowest cost power generation and low cost purchases" and "retail customers are inappropriately bearing 100% of the excessive cost of power that TECO must purchase to replace unreliable internal generation." I believe it would be helpful to explain the flaws in these two findings, which then explains why his first conclusion is erroneous.

Q. Please help explain the flaws in his first "finding".

A. When describing wholesale customers, Mr. Collins appears to be referring to parties that have entered into long-term, separated firm wholesale sales agreements with Tampa Electric. Most of these sales were initiated in the early 1990's. All sales were made under FERC-approved, cost-based contracts prior to deregulation of the wholesale market. Currently Tampa Electric has 320 MW of separated firm wholesale sales that comprise less than 10 percent of Tampa Electric's firm load. Of this amount, 145 MW are unit power sales and 175 MW are system sales. As described in the rebuttal testimony of Tampa Electric's witness Denise Jordan, under the Commission's established policy, these types of sales are separated from Tampa Electric's retail jurisdiction removing all generating plant and operating expenses associated with the sale.

Q. Why did Tampa Electric enter into these long-term firm contracts?

A. Tampa Electric entered into these agreements in order to more efficiently and economically utilize its generating capacity. When each of these sales was initiated, Tampa Electric had excess capacity sufficient to make these sales and still meet its required planning reserve requirement for serving firm retail load.

Q. What about Mr. Collins' "finding" that "retail customers are inappropriately bearing 100% of the excessive cost of power that TECO must purchase to replace unreliable internal generation"? Is it correct?

A. Absolutely not. As described by Ms. Jordan, for the majority of wholesale sales agreements, the fuel factor charged is the average system fuel cost which consists of Tampa Electric's own generation fuel expenses and purchased power costs. Messrs. Collins' and Pollock's testimonies make this erroneous statement throughout.

Q. What is erroneous about the statement in Mr. Collins' "finding" that "wholesale customers receive the benefit of TECO's lowest cost power generation and low cost purchases?"

A. The majority of Tampa Electric's wholesale contracts are separated, long-term, system-based sales wherein wholesale customers are treated similarly to firm retail load. Therefore, to make a blanket statement that wholesale customers receive the benefit of the company's lowest cost power generation and low cost purchases is incorrect.

<u>FIPUG's Three Conclusions Based on an "Audit"</u>

Q. With that explanation of two of the "findings", please address Mr. Collins' reference to "more expensive replacement power" and his reference to "low cost native generation to wholesale customers" in his first conclusion.

A. Purchased power costs have increased in recent years for many of the reasons cited by FIPUG's own witness, Mr. Pollock. Tampa Electric does not have the ability to use its own discretion to charge purchased power costs to its separated wholesale customers. It charges fuel and purchased power costs in accordance with its FERC-approved contracts.

Mr. Collins' criticisms are based on nothing more than a hindsight comparison of the prices specified in the long-term, cost-based contracts compared to the higher priced market-based purchased power that utilities have incurred in recent years. He has presented no evidence that there is anything inappropriate in how Tampa Electric has charged purchased power to customers.

Q. Please address Mr. Collins' second conclusion that Tampa Electric "has been purchasing low cost power on the wholesale market and reselling it to wholesale customers, rather than using it to reduce fuel costs paid by retail customers."

A. The testimony of Messrs. Collins and Pollock contain contradictory issues and conclusions. Mr. Pollock recommends that "TECO should be ordered to cease its current practice of allocating 100% of replacement power costs to retail customers" (which is not the case as I stated above). Furthermore, Mr. Collins asserts that "TECO allocated zero costs of replacement power to wholesale customers" (again, which is incorrect) yet he concludes that certain purchased power <u>should</u> be allocated to retail customers and not to wholesale customers as Tampa Electric did when it purchased power from PECO and allocated it to a wholesale sale. Once one is able to wade through FIPUG's inconsistent statements, it becomes apparent that their position is that as long as the price of purchased power is low, the costs should be allocated to retail customers but if the price is high, the costs should be allocated to wholesale customers. This practice is not consistent with any regulatory practice or policy and it certainly does not align with wholesale contractual agreements under which the company is obligated as a party.

Q. Please respond to Mr. Collins' third conclusion that wholesale customers have continued to receive their full entitlement of "low cost, native load generation, despite extensive outages and deratings of native generation, including specific generators dedicated to wholesale sales."

A. This conclusion simply states that Tampa Electric has met its contractual obligations under its separated wholesale sales. Wholesale customers have continued to receive their full entitlement in accordance with the terms of their contracts. Unit power sales are dependent upon the availability of one or more designated generating units, whereas system sales are treated similarly to firm retail customer load. Mr. Collins states that wholesale customers should bear some of the consequences resulting from unit outages. Wholesale customers do bear the consequences resulting from unit outages. For example, Tampa Electric engaged in only one unit power sale this summer, a sale that has been in existence for almost 10 years. The sale was cut for many hours due to planned and unplanned unit outages. The wholesale customer in this sale was required, by contract, to locate and purchase replacement power on the wholesale market at the then current market price. However, Tampa Electric's retail customers continued to receive service during these periods. It appears Mr. Collins would have Tampa Electric breach firm service wholesale obligations to prevent interrupting a non-firm retail customer.

Flaws in "Subsidy" Calculation

Q. Please comment on Mr. Collins derivation of his alleged retail customer "subsidy" of Tampa Electric's wholesale sales.

A. Mr. Collins' "subsidy" calculation is arbitrary and lacks any traceable logic. To create the "subsidy," Mr. Collins testifies that he relied on a deliberate data set drawn from 21 days in a three-year period, 1999-2001, during which interruptible customers were being interrupted while Tampa Electric was purchasing power. Using this information, Mr. Collins arbitrarily assigns a system average purchased power responsibility for the hour in question to wholesale sales, conveniently ignoring the contractual terms of the agreements. He then subtracts the actual cost from his calculated cost and derives his "subsidy." Mr. Collins' testimony is predicated upon rewriting Tampa Electric's long-term firm separated contracts to require the use of a system average fuel cost rather than the unit specific or station specific fuel costs contained in contracts. He also overlooks the fact that full and partial-requirements customers do indeed pay their fair share of purchased power expenses.

Q. Does Mr. Collins' calculation of any alleged "subsidy" have any merit?

A. Absolutely not. Mr. Collins focuses on only 63 hours during 21 days when the interruption of interruptible customers coincides with power being purchased by Tampa Electric. His 63 hours, extrapolated over a three-year period, were guaranteed to produce the highest differential between purchased power costs and the on-going costs of power sold under cost-based wholesale contracts. Mr. Collins then takes this worst case scenario and annualizes it for all 26,280 hours of the three-year period. Stated differently, Mr. Collins handpicks 2/1000 of the hours in the period and then uses these hours as a purported fair sampling to extrapolate results over a three-year period.

Two of Mr. Collins' handpicked hours on July 6, 2000 showed actual firm wholesale sales in excess of maximum allowable contract demand (Exhibit BCC-9, page 1 of 2). He insinuates that Tampa Electric acted imprudently by over-selling its firm capacity. Upon review of these two hours, Tampa Electric supplied up to 245 MW of cost-based emergency power sales to another Florida utility to help prevent firm load curtailment on their system. Mr. Collins goes on to apply his "objectively derived" "subsidy" factor to every megawatt hour of sales made under Tampa Electric's separated sales without regard to understanding the circumstances.

Another flaw in Mr. Collins' "audit" is that he applies his "subsidy" factor to all wholesale sales - thereby co-mingling separated wholesale sales with short-term non-firm sales. He does not attempt to calculate and, indeed, summarily dismisses the gains that Tampa Electric has made on these non-separated sales, gains that flow directly to the benefit of Tampa Electric's retail customers.

Q. Do these non-separated sales adversely impact interruptible customers?

A. No, they benefit all retail customers. Again, Tampa Electric only makes these sales when they are expected to produce an economic benefit to its general body of retail customers. As I have testified previously, when the company is making a non-firm non-separated sale, it ramps out of such a sale any time interruptible customers might be interrupted or optional provision power must be purchased in order to serve them. Even given these protections of interruptible customers, Mr. Collins chooses to totally ignore the benefits of non-separated sales.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Sir, would you please summarize your rebuttal testimony.

A Good morning, Commissioners. My rebuttal testimony addresses certain deficiencies in the prepared direct testimony of FIPUG's witnesses, Mr. Brian Collins and Mr. Jeffry Pollock. These issues were discussed yesterday. Tampa Electric has only one separated wholesale sale that is not priced based on system average cost. It is the Big Bend Unit Number 4 sale to TECO Power Services, a sale that has been in existence for almost ten years. That sale was one component of a need determination proposal for what is now Hardee Power Station. The Commission approved that project finding that it would save the customers of Tampa Electric and Seminole Electric Cooperative millions of dollars. The loss of this unit requires the wholesale customer to purchase replacement power on the wholesale market at the then current market price.

In summary, FIPUG's witnesses have leveled unjustified criticisms regarding Tampa Electric's allocation of purchased power between its retail and wholesale customers. Tampa Electric has simply abided by its long-term wholesale contractual commitments, the treatment of which was approved by this Commission. This concludes my summary.

MR. BEASLEY: Thank you. The witness is available for questions.

CHAIRMAN JACOBS: Mr. Vandiver.

MR. VANDIVER: No questions.

CHAIRMAN JACOBS: Mr. Cloud.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Brown, you said that customers saved millions of dollars as a result of the transaction by which Big Bend 4 was sold to Hardee Power Partners. Is that the transaction you were talking about that saved millions of dollars?

A Yes, yes.

Q And yesterday, Mr. Beasley said that Tampa Electric saved $90 million -- or the customers saved $90 million as a result of that transaction. Do you recall him saying that?

A I believe he said that the customers of Tampa Electric Company were forecasted to save $90 million as a result of that transaction.

Q And that is dealt with in the Order 92034 (sic) that he proffered into evidence requesting the Commission to take official recognition?

A I believe that was the order number. I don't recall exactly.

Q But the $90 million, according to that order, is based upon deferring -- Tampa Electric deferring 225 megawatts of previously planned CT capacity. Had Tampa Electric planned to bill 225 megawatts of capacity that it didn't bill as a result of this determination?

MR. BEASLEY: If Mr. McWhirter is referring to something in that order, I think the witness needs to be shown what it is he's referring to.

BY MR. McWHIRTER:

Q Go ahead and read that last paragraph, and I think it will be helpful.

(Pause.)

A Yes, I've read it.

Q Read it aloud, if you will.

A The entire paragraph?

Q Yes.

A "The Commission based the need finding on the economics inherent in the wholesale contracts between TPS, SEC, and Tampa Electric, Order Number 22335. In Phase I, parentheses, 1993 through 2003, TPS will construct 295 megawatts of combined cycle capacity and TECO will sell 145 megawatts of Big Bend 4 capacity to SEC. And in Phase II, parentheses, 2003 through 2013, TPS will replace the Big Bend 4 capacity by constructing a 70-megawatt heat recovery unit and one 75-megawatt CT at the Polk/Hardee site for sale to SEC, parentheses, TR254, close parentheses.

"The combination of the sale of existing Big Bend 4 capacity and constructing new TPS capacity was preferred to the option of SEC constructing two 220-megawatt combined cycle units in 1993. The TPS proposal resulted in projected present worth of revenue requirement savings to SEC of approximately 57 million, parentheses, 1997 dollars and 90 million, parentheses, 1989 -- excuse me, 57 million, parentheses, 1987 dollars and present worth -- a projected present worth requirement savings of 90 million, parentheses, 1989 dollars to Tampa Electric based on the deferral of 225 megawatts of previously planned CT capacity on Tampa Electric's system, parentheses, Order Number 22335, close parentheses."

Q All right. Now, did Tampa Electric, in fact, defer constructing 225 megawatts of capacity?

A As far as I know, we did.

Q And in fact, you not only deferred it, but you transferred 145 megawatts of Big Bend away to your affiliated company, Hardee Power; is that correct?

A The sale of 145 megawatts to Hardee Power Partners was included in this deal, yes, sir.

Q And so were those -- had the Commission previously determined that the -- Tampa Electric needed the 145 megawatts of capacity to serve its retail load and would need the 225 megawatts of capacity to serve the retail load?

A I don't know. I'm not that familiar with the need determination details.

Q Would it be fair to say that the results of that transaction were that -- strike that question.

Yesterday, you were handed -- or, I guess, Mr. Collins was handed an exhibit which showed the units that were constructed before the 1997 Commission fuel order and the units -- or the contracts that were entered into after the '97 order. Do you recall that exhibit?

A I do recall an exhibit being discussed to that effect, yes.

Q It shows that on January the 1st, 1998, Tampa Electric entered into a contract to sell 75 megawatts of firm capacity to Reedy Creek; is that correct?

A Let me check the exhibit. Thank you. The Reedy Creek contract that you're referring to, which the term of the sale begins 1/1/98, I think that's the one you're referring to, the 75-megawatt requirement sale.

Q Yes.

A That contract was actually entered into much earlier than 1998. Looking at Interrogatory -- staff's set, Interrogatory Number 4, and our response, Page 2 of 4, that contract was entered into March the 29th, 1995.

Q And what was the capacity that was committed under that contract?

A It was committed at that time, yes, sir.

Q How much capacity?

A Up to 75 megawatts.

Q And your exhibit -- yesterday, it shows 15 megawatts. Is that an error?

A No. Actually, there was another contract which was a unit power sale -- there was a separate contract for 15 megawatts.

Q So you've committed 90 megawatts to Reedy Creek?

A That unit -- that 15-megawatt unit power sale only existed for nine months in 1998. It was a nonseparated sale that only lasted nine months.

Q During 1998 was Reedy Creek able to call upon that 15 megawatts when DSM and interruptible customers were being interrupted?

A Yes.

Q Did they, in fact, call on it?

A I believe they did.

Q Are they currently calling on the 75 megawatts of capacity that's dedicated under the January 1, '98 contract which was --

A The requirements contract, yes, sir.

Q Yes, sir.

Did you come to the Commission at that time to demonstrate the benefits that utility customers would receive from this contract?

A Back in 1995 or '96 when that -- I do not know.

Q Well, the '95 or '96 contract expired, and this was a new deal in '98, wasn't it?

A No. I'm referring to the date that the contract was entered into in 1995 or '96. Both of these contracts started in '98, January 1st of '98 as you can see from the exhibit. I do not know what was done back then before this Commission. The 75-megawatt contract is a requirements service. So it's actually served under a tariff, requirements to AR-1 tariff, wherein the load is treated the same as firm retail load.

Q And that -- my question to you was, is that load served while DSM and interruptible customers are being interrupted?

A Yes. It is treated the same as firm retail load.

Q Are you -- is that a separated or a nonseparated sale?

A That is a separated sale.

Q And as a result of the separated sale, the fuel revenue goes to the customers of Tampa Electric. They're credited with that through the fuel clause, is that correct, on average system cost?

A System average cost, yeah, that's correct, and purchased power is allocated to that contract as well.

Q And according to Ms. Jordan's Exhibit Number E1, that system average cost for the forthcoming year is $27.78 (sic) that's booked for the benefit of retail customers?

A I'll just assume that that's correct, yes, sir.

Q Is that all the money that's collected under that contract?

A No, that -- I believe that's the forecast of the fuel. What's actually collected is based on actual and it's trued up. Is that -- am I answering your question?

Q No. I was asking if the $27.73 is the amount that will be credited for the benefit of the retail customers if that forecast proves accurate.

A I really don't know. That would be an appropriate question for Ms. Jordan.

Q Would the retail customers receive any of the revenue from the remainder of the collections from Reedy Creek?

A Well, requirements -- fuel is a pass-through, if you will, to the requirements customers, and that would apply not only to Reedy Creek, but all of the other requirement sales that we have. In other words, native retail customers are not impacted one way or the other. The requirements customers are treated the same way from a fuel standpoint as native -- firm native retail customers. So there is no harm to firm native retail customers.

Q And was there a rate case in 1995 that removed this 75 megawatts from the retail rate base?

A I don't know.

Q When was Tampa Electric's last general rate case?

A I don't know.

Q If there had been no general rate case, then for base rate purposes, this 75 megawatts would not have been considered removed from the company's rate base, question mark. I'm sorry that's a poorly worded question.

I'm trying to -- and you may not know this from a regulatory aspect, but it's a separated sale; is that correct?

A Yes, sir.

Q And 75 megawatts is dedicated to Reedy Creek rather than the retail customers; is that correct?

A That's correct.

Q And when you have a general rate case, that 75 megawatts is removed from the rate base and customers no longer have to pay a return on that.

A Well, they no longer have to pay the capacity --

Q No longer have to pay the capacity.

A -- and the charge is the capital charge.

Q Okay. My question to you is that, to your knowledge, have customers been relieved of the obligation to pay for that 75 megawatts post-1975?

A As far as I know, but that would be a question more appropriate for Witness Jordan.

Q Ms. Jordan could answer that?

A Yes. Yes, it would.

Q All right. Now, your deposition was taken, and the staff asked you to file a late-filed exhibit. That's Exhibit

Number 4. Would you look at that, please.

A Okay.

Q Does that exhibit accurately reflect the deliveries to Reedy Creek between January and August of 2001?

A The late-filed exhibit which was to provide deliveries between January and August of 2001 -- I need to go back and look at the actual exhibit request to answer that question. I do have the response, but I don't have the question. Do you have the question?

Q Well, you presume your response was truthful, don't you?

A Oh, yes.

Q All right. So you have sold 307,919 megawatt hours of electricity for the first eight months of the year to Reedy Creek?

A I'm not sure this is a sale. I believe this response was in -- this was in response to a purchased question or purchased exhibit. Again, I'd have to look at the exhibit.

MR. BEASLEY: If he needs to look at the request, I think it's appropriate that he be allowed to do that.

CHAIRMAN JACOBS: The interrogatory request, is that what you're saying?

MR. BEASLEY: Yes, sir.

THE WITNESS: It's the exhibit request, yes, sir.

CHAIRMAN JACOBS: Is that available?

MS. GORDON-KAUFMAN: Yes.

MR. McWHIRTER: Well, that's the exhibit. He needs to look at what they asked for in the deposition.

BY MR. McWHIRTER:

Q Is that what you're saying?

A Yes.

Q Do you have any recollection of what was asked for in the deposition?

Bear with us momentarily.

CHAIRMAN JACOBS: Staff, do you have an idea where in the transcript that might be?

Q Does that refresh your recollection -- you haven't got it yet.

MS. GORDON-KAUFMAN: (Tendering document.)

BY MR. McWHIRTER:

Q Okay. You got it. Page 63 of the deposition, the bottom of the page.

A Okay. This request was for all -- well, let me just read it. It says, "You've agreed to provide us with Late-Filed Exhibit 4, which will consist of a listing of megawatt hours by month and the cost of these megawatt hours by month for the months January 2001 through August 2001 for megawatt hours delivered under long-term contracts signed in 2000 and 2001. Also, in that late-filed exhibit you will provide us with your definition of long-term contracts, whether you -- whatever you define long-term contract to be."

Q Is your answer to 4 responsive to that request?

A Yes, it is.

Q And did you deliver 307,919 megawatt hours to Reedy Creek?

A This Exhibit 4 is a request for purchased power information, not sales information.

Q This is what you purchased from Reedy Creek?

A Yes, sir. Yes, sir, it is. That's why I was getting confused.

Q I see. So you purchased 370?

A That's correct.

Q And you paid $32,000,341 for that purchased power?

A That's correct.

Q And that works out to $105.03 a megawatt hour that you paid Reedy Creek?

A No, sir. This is not from Reedy Creek. These are purchases from all long-term contracts that were signed in 2000 and 2001.

Q So it doesn't have anything to do with Reedy Creek?

A It has nothing to do with the sale to Reedy Creek.

Q Okay. During that period of time, you were making sales to Reedy Creek?

A Yes, we were.

Q And what were you charging Reedy Creek for those sales?

A System average fuel cost.

Q Were you charging them any additional money?

A No, sir.

Q Your contract with Reedy Creek commits power, but it does not require Reedy Creek to pay anything more than system average fuel cost?

A No, it does not. They pay the system average fuel cost which includes a portion of purchased power.

Q I understand that, but they don't pay anything at all for the capacity that's committed to them to the exclusion of other retail customers?

A Oh, yes, they have a capacity charge. Yes, sir.

Q And how much was sold to Reedy Creek during that period of time? Do you know?

A I don't have the numbers in front of me, no.

Q Were they taking -- they're entitled to 75 megawatts. Were they taking all of that?

A During some of the time, they were.

Q So in an average month that's 730 hours?

A I guess I don't follow you. 730 hours?

Q Twenty-four days times -- I mean, 24 hours a day times 30 days would be 720, and if you averaged in 365 days a year, it comes out to 730 hours a month; is that correct?

A Well, their take is not 24 hours a day. It's less than that.

Q It's just during the peak periods?

A Their take is -- no, not necessarily during the peak periods because the system average fuel cost will dispatch fairly well for them, so their take is somewhere around 16 hours a day.

Q Sixteen hours a day, and just the off-peak period or the on-peak period or a combination?

A That would be an on-peak 16 hours a day approximately five, maybe seven, days a week.

COMMISSIONER DEASON: Let me ask a question at this point. How do you calculate system average fuel costs for purposes of these sales?

THE WITNESS: I'm afraid I can't answer that question. Ms. Jordan could more appropriately answer it.

COMMISSIONER DEASON: All right. Very well.

BY MR. McWHIRTER:

Q But there's a sum of money collected by Tampa Electric for these sales to Reedy Creek over and above the $27.73 average fuel cost; correct?

A We collect a capacity charge, and we collect an energy charge. The energy charge has the fuel cost in it.

Q And what is the capacity charge?

A The exact capacity charge is $9.42 per kW month.

Q And what would that add up to in dollars per month?

A Well, it depends on their take, but that's a per unit figure. And if they take 10 megawatts that month, then it would be 10 times 1,000 times $9.42.

Q Which would be what?

A It would be $94,200, I believe, if my math is correct.

Q Let's say they took 75 megawatts. Is the capacity charge based opinion the maximum demand in the month or is it --

A Yes, it is.

Q So if they took their full 75 megawatts, it would be 75 megawatts times --

A Times a thousand.

Q -- times a thousand.

A Times $9.42.

Q So that would be $706,500 --

A I assume.

Q -- a month.

A That sounds reasonable.

Q And if they collected -- they took their maximum demand each month for 12 months, that would be $8 million that Tampa Electric will collect in capacity charges from Reedy Creek; is that correct?

A That sounds reasonable, based on your numbers.

Q Do they ever take more than that 75 megawatts?

A No.

Q There's no -- there is a restriction on the demand that they can trigger?

A Yes, there is.

Q How do you monitor that restriction?

A Well, it's monitored by our energy control center through metering.

Q And if their immediate demand is 90 megawatts, what do you do about it? What does the energy control center do about it?

A They contract -- they contact -- that normally is not the case; it doesn't happen. But if it should happen, they would contact the energy control center at Reedy Creek, and they would adjust their inadvertent. It would be counted as inadvertent rather than contract demand. They would adjust that inadvertent normally within an hour.

Q Would it be correct to say that from that sale, retail customers get a credit against fuel cost for system average fuel cost at the rate of $27.73 a megawatt hour, and Tampa Electric gets around $700,000 a month that goes to the earnings of Tampa Electric Company but is not flowed through the fuel clause to the customers; is that correct?

A The fuel is not -- the fuel cost of the Reedy Creek is paid for by Reedy Creek. What they're paying for is a slice of the system, which is requirement service. The capacity charge, the $9.42, goes to the company to pay for the separated assets, the assets that are separated for that sale. This is a cost-based sale, it's not a market-based sale.

Q And is it fair to say that you don't know whether that slice of the system has been removed from the rate base for the year 2000 and the year 2001 and the year 2002?

A Well, I assume it has, but that's an appropriate question for Witness Jordan.

Q And you wouldn't know if it were removed from the rate base how customers would benefit from that removal?

A They would benefit in paying a lower base rate, but that would, again, be an appropriate question --

Q If it had been removed.

A Pardon me?

Q If it were removed.

A Yes, sir. That would be another appropriate question for Witness Jordan.

Q All right. Now, the other big sale during this current year and the year 2000 was to 145 megawatts to your affiliated company, Hardee Power Partners; is that correct?

A Yes.

Q And with respect to that sale, Hardee Power Partners paid the fuel cost that was -- is the average fuel cost to operate Big Bend 4. Is that essentially it?

A Yes.

Q And what is that price?
A It actually varies every month. It's based on the actual for each month, and it's a combination of fuel and O&M expenses, incremental O&M, to serve the sale, but it's approximately $30.
Q It's $30?
A Approximately. That includes the O&M fees.
Q The O&M fees.
What's the fuel component of it?
A The fuel varies. It depends on whatever the coal costs that month. I think it's around $25, $26 in a typical month.
Q And the O&M costs, Tampa Electric keeps that. It doesn't flow that back to the customers; is that correct?
A I believe that's the case, but, again, Witness Jordan would be the appropriate person to ask.
Q And if during the period between January and August of the year 2001 you didn't have enough capacity to meet the consumers' -- the retail consumers' electrical demands, you would buy that capacity and, in fact, did buy that capacity at a price of $105.03 a megawatt hour; is that correct?
MR. BEASLEY: Is that on a document you're referring to that number?
MR. McWHIRTER: The number I'm referring to is the $32 million that was paid for purchased power divided by the

307,000-megawatt hours purchased during that eight-month period.

A And I'm sorry, could you repeat your question, please.

Q Surely. According to your answer to question number four -- or for Late-Filed Exhibit 4, Tampa Electric has paid $32,000,341 for purchased power during the period January through August; is that correct?

A That represents only long-term purchased power contracts that we entered into in response to that late exhibit request. It does not include --

Q So in your long-term contracts, you paid that amount?

A Pardon me?

Q Your long-term contracts --

A That's correct. It does not include short-term purchases.

Q That's not spot market power?

A That's correct.

Q Okay. And you purchased 307,919 megawatts under long-term contracts?

A That's correct.

Q And if you wanted to know how much that came to per megawatt hour, you would divide the 32 million number by the 307,000 number?

A That's correct.

Q And will you agree with me, subject to check, that that amounts to $105.03 a megawatt hour that is charged for the fuel cost under that contract, or the total cost?

A That's the total cost. That includes the capacity component, I believe.

Q I see. And is all of that $105 charged to retail customers?

A That $32 million --

Q Yes.

A -- is all charged to retail and wholesale requirements customers.

Q Whatever their relative percentage is?

A That's correct.

Q But none of it is charged to your affiliated company, Hardee Power Partners; is that correct?

A Not under the Big Bend 4 agreement, no.

Q Because they pay $21?

A No, they pay about $30.

Q Thirty dollars.

And the last time anyone reviewed the benefits of that transaction was in 1987?

A The -- I believe the date on the need determination decision was 1989.

Q In 1989?

A As I recall.

Q That's the last time that was reviewed?
A As far as I know, yes.
Q And the price that's paid under that contract, is that approved by this Commission or by the Federal Energy Regulatory Commission?
A The price is actually a cost-based price. It's a cost-based contract that was approved by the Federal Energy Regulatory Commission. However, the treatment of this sale was determined by this Commission.
Q If this Commission determined that the cost was too low, under your understanding of how these things operate, could the Commission require your affiliated company to pay more money under current conditions for the purchase of that power?
A I don't know the answer to that.
Q Do you know in establishing the price paid under contracts which Commission has superior authority with respect to what the load serving utility Tampa Electric is required to pay?
MR. BEASLEY: Mr. Chairman, that calls for a legal conclusion on the part of the witness. I object.
CHAIRMAN JACOBS: Mr. McWhirter.
MR. McWHIRTER: Well, you want -- he's objecting to the question because it's calling for a legal conclusion?
CHAIRMAN JACOBS: Uh-huh.

MR. McWHIRTER: I accept that objection.

BY MR. McWHIRTER:

Q Have you put in any testimony in this case, Mr. Brown, that deals with your contracts and whether or not those contracts could be breached?

A No, I have not.

Q Have you drawn any legal conclusions in your testimony?

A I have not drawn any legal conclusions; however, we abide by the terms and the conditions of our contracts.

Q And you do not know of your own knowledge without legal advice whether or not this Commission could require Hardee Power Partners, the affiliated company, to charge -- for Tampa Electric to charge Hardee Power Partners a larger sum than it's currently charging?

A You mean as a hindsight determination?

Q Yes.

A No, I do not know.

Q And according to your response in late-filed -- the Late-Filed Exhibit Number 6, the current capacity payment by Tampa Electric to Hardee is $20.18 a megawatt hour, and Tampa Electric pays Hardee $53.99 a megawatt hour for fuel for a total of $74.17 a megawatt hour.

A That was based on the January through July of 2001 data, and understand that the capacity payment is determined on a megawatt hour basis in this exhibit. That is not actually the capacity payment on a dollars per kW month, but it's based rather on the load factor for that particular period.

Q Something like $13 million a year according to the 1992 rate order, or is it more than that?

A I don't know what the total number was.

Q Okay. What would happen if you -- instead of using Big Bend 4 capacity you used Hardee capacity to reach your commitments to Seminole, how would the customers of Tampa Electric be affected?

A If we -- let me make sure I understand your question. Are you asking, if we took the Big Bend 4 capacity and put it back into rate base --

Q Right.

A -- and then served the Seminole contract -- or the Hardee Power Station/Seminole contract with Hardee Power Station -- 145 megawatts of Hardee Power, is that your question?

Q Yes.

A I don't know what that calculation would reveal. Once you put all that coal-fired capacity back in rate base, they -- I really don't know.

MR. McWHIRTER: That's all the questions I have of this witness.

CHAIRMAN JACOBS: Staff.

MR. KEATING: No questions.

CHAIRMAN JACOBS: Commissioners.

COMMISSIONER DEASON: No questions.

CHAIRMAN JACOBS: Mr. Brown, are you familiar with -- I guess we've identified this as Exhibit 8, and it is FIPUG's second set of interrogatories, specifically Interrogatory Number 29. Are you familiar with that? And let me read it to you so that you will hear. Referring to Tampa Electric's response to Interrogatory Number 14, "Please provide the following information for each firm wholesale sale contract term, contract capacity type of wholesale sale."

THE WITNESS: Yes, sir.

CHAIRMAN JACOBS: And then there's a chart under there. As I understand this chart, it is looking to identify wholesale sales that were under contract, I guess, prior to -- they were entered into prior to the time line that has been discussed; is that correct?

THE WITNESS: I believe that's true, yes, sir.

CHAIRMAN JACOBS: And as I understand the representation of this response, it is that all of the expense -- fuel expense associated with any of these contracts, it flows through the clause but also any revenues related to fuel flow through the clause as well. Is that the case?

THE WITNESS: I'm sorry, could you repeat your question? I was having difficulty hearing.

CHAIRMAN JACOBS: Both -- in A-D, it says, "Both the fuel revenue and fuel expense associated with the aforementioned sales are flowed through the fuel cost recovery clause or netted resulting in no impact to retail ratepayers."

THE WITNESS: Yes, sir, as far as I know. Yes.

CHAIRMAN JACOBS: Are you familiar with that process?

THE WITNESS: Not thoroughly familiar. Witness Jordan is really more familiar with that process than I am.

CHAIRMAN JACOBS: Okay. Thank you.

Redirect.

MR. BEASLEY: Just one.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Was that document prepared under your direction or supervision?

A This is Interrogatory Number 29 --

Q Yes.

A -- that you're referring to of FIPUG's second set of interrogatories? Yes, it is.

MR. BEASLEY: Thank you. That's all I have.

CHAIRMAN JACOBS: No exhibits. Thank you. You're excused, Mr. Brown.

(Witness excused.)

MR. BEASLEY: Call Ms. Jordan.

J. DENISE JORDAN

was called as a rebuttal witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Jordan, was your prepared rebuttal testimony prepared by you?

A Yes, it was.

Q If I were to ask you the questions contained in that rebuttal testimony, would your answers be the same?

A They would.

MR. BEASLEY: I'd ask that Ms. Jordan's testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Ms. Jordan's rebuttal testimony is entered into the record as though read.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") as Director, Rates and Planning in the Regulatory Affairs Department.

Q. Are you the same J. Denise Jordan who has presented Prepared Direct Testimony in this proceeding?

A. Yes I am.

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to highlight the deficiencies and inaccuracies of the testimony of Mr. Jeffry Pollock, testifying on behalf of the Florida Industrial Power Users Group ("FIPUG"). Because FIPUG's other witness, Mr. Brian Collins, refers to Mr. Pollock's testimony, I must occasionally refer to his testimony as well, however Tampa Electric's witness, Lynn Brown, addresses most of Mr. Collins' testimony, particularly the portion Mr. Collins refers to as his "audit."

Q. Have you prepared any exhibits to support your testimony?

A. Yes. My Exhibit No. ____ (JDJ-4) is furnished as support for the calculation of the projected 2002 wholesale average system fuel cost adjustment.

Q. Please address your overall assessment of FIPUG's testimony.

A. Mr. Pollock's testimony is largely duplicative of the testimony submitted by Mr. Collins. Mr. Pollock makes the erroneous conclusion that Tampa Electric favors its wholesale customers at the expense of its retail customers. Like Mr. Collins, Mr. Pollock ignores the fact that all of the investment and O&M expenses associated with the generating capacity serving Tampa Electric's long-term firm wholesale customers is separated from the retail jurisdiction, meaning that the company's retail rates do not include the costs associated with making these sales. Therefore, retail customers do not pay for separated wholesale sales.

Both Messrs. Pollock and Collins fail to realize or acknowledge that currently with the exception of one unit power sale, all other separated sales are charged average system fuel costs which includes not only the fuel costs for Tampa Electric's own generation, but the costs for purchased power as well. Exhibit No. _____(JDJ-4) demonstrates the calculation of the 2002 projected average system fuel cost adjustment. The total system fuel and net power transaction costs are the same costs as shown in the 2002 retail fuel and purchased power cost recovery clause calculation Schedule E-1 on page 24 of my testimony filed on September 20, 2001. In addition, just as with the retail fuel cost recovery, there is a true-up mechanism for wholesale fuel and purchased power expenses. It appears that both Messrs. Pollock and Collins have overlooked the components of the average system fuel costs and the true up mechanism. As a result, they have incorrectly concluded that 100 percent of the costs of purchased power is borne by retail ratepayers.

Like Mr. Collins, Mr. Pollock blurs the distinction between separated wholesale sales (for which the retail customers do not pay) and the company's non-separated sales (which significantly benefit Tampa Electric's retail customers and do not cause interruptions or buy-through power purchases for interruptible customers). Also, like Mr. Collins, Mr. Pollock ignores that this Commission has specifically addressed the fuel adjustment treatment of long-term separated wholesale sales in previous dockets.

Perhaps the greatest indictment of Mr. Pollock's testimony is the fact that he accepts and relies on the "audit" prepared by Mr. Collins and the conclusions he draws therefrom. The overwhelming defects of Mr. Collins' "audit" and his resulting flawed conclusions are described in witness Brown's rebuttal testimony.

Finally, Mr. Pollock's testimony, like so many of FIPUG's recent efforts in this and other dockets, seeks to postpone or avoid Tampa Electric's recovery of legitimate fuel and purchased power costs. Mr. Pollock does so based on the absolutely erroneous ground that Tampa Electric has failed to provide FIPUG with information necessary for the preparation of intervenor testimony.

Alleged Delays and Reluctance in Providing FIPUG Information

Q. What information has Tampa Electric provided to FIPUG in this docket?

A. Tampa Electric has provided everything FIPUG requested with the exception of one interrogatory and two subparts of a second interrogatory regarding highly proprietary coal pricing information - a topic which is not addressed in Mr. Collins' "audit" or Mr. Pollock's testimony. All information was provided in a timely manner.

Q. Please describe the extent of Tampa Electric's responses to discovery requests from FIPUG.

A. In this docket, the company has responded to over 85 discovery requests including some 195 subparts. Twenty-five of these items asked for hourly data and 164 of them asked for information covering multiple years. In total, Tampa Electric has provided over 1,300 pages of interrogatory responses and nearly 6,000 pages of documents requested by FIPUG. It is absurd for FIPUG's witnesses to make allegations that the company has resisted in responding and has not provided the required data in a timely manner without having all of the facts before them.

Q. Did Tampa Electric resist and/or delay providing its responses to FIPUG?

A. Absolutely not. Tampa Electric even offered on several occasions, beginning as early as May 8, 2001, to supply FIPUG with highly competitive and confidential information the company had objected to if FIPUG would sign a non-disclosure agreement. These offers went unanswered by FIPUG until August 20, 2001. Tampa Electric has accommodated FIPUG's extensive discovery requests, and Mr. Pollock, like Mr. Collins, has stated no basis for claiming otherwise. While the suggestion of delay and resistance is consistent with FIPUG's standard approach, their arguments in this regard lack merit and should be rejected.

Other Inaccurate Assertions and Statements

Q. Please comment on FIPUG's assertion that Tampa Electric allocates 100 percent of it purchased power costs to retail customers.

A. This assertion is categorically incorrect. Unfortunately for FIPUG, it based a significant portion of its "audit" and "analysis" on this erroneous assumption. Certainly the contractual terms of separated sales must be adhered to, but for the majority of wholesale sales agreements, the fuel factor charged is the average system fuel costs, which as I stated earlier consist of Tampa Electric's own generation fuel expenses and purchased power costs. There is also a true-up provision similar to that employed in the retail jurisdiction to ensure the collection of the fuel and net power transaction costs.

FIPUG's Recommended Actions

Q. Please comment on Mr. Pollock's recommended action that "separated sales should be charged average system fuel and purchased power costs, while non-separated sales should be charged system incremental costs."

A. I partially agree with Mr. Pollock, only because his recommendation is somewhat consistent with this Commission's established policies. Order No. PSC-97-0262-FOF-EI in Docket No. 970001-EI issued March 11, 1997 requires that separated sales, on a prospective basis, be credited at average system fuel cost. For those contracts entered before the order date, contractual terms will dictate price and cost responsibility. Non-separated sales being charged at system incremental costs is the subject of an open docket, Docket No. 010283-EI, (interestingly, contested by FIPUG regarding the definition of "incremental") and is supported by Tampa Electric.

Q. How do you respond to Mr. Pollock's first recommended action outlined on page 6 of his testimony regarding allocating a portion of purchased power to wholesale sales?

A. FIPUG will be pleased to know that Tampa Electric is already complying with the terms they recommend. The company is complying with Order No. PSC-97-0262-FOF-EI for separated sales and is charging system incremental costs for non-separated sales.

Q. Please respond to FIPUG's second recommended action as stated on page 6 of Mr. Pollock's testimony having to do with the opening of a separate docket.

A. As Tampa Electric's testimony has proven, along with the annual audits performed for the periods in question by the Commission's staff, the company has appropriately managed its long-term wholesale contracts. Furthermore, Tampa Electric has been responsive to FIPUG's discovery requests. Between the information the company has provided both to FIPUG and to the Commission Staff, the review of Tampa Electric's long-term separated wholesale contracts by the Commission and the FERC and the detailed audits this Commission has performed, there is simply no justification for the creation of a separate docket. Certainly FIPUG's unfounded speculation and misuse of data do not warrant such action.

Q. Please respond to FIPUG's third recommended action to hold Tampa Electric's fuel and purchased power true up in abeyance.

A. It is unnecessary to hold the company's under-recovery in abeyance pending the outcome of any separate new docket. This is an on-going docket and as stated above, all of FIPUG's assertions have been reviewed and will continue to be reviewed by this Commission. FIPUG continues to attempt to reach as far back as 1999 in an attempt to allege some type of inappropriate action. FIPUG has not revealed anything new and this Commission has already exhaustively reviewed the periods in question. The bottom line is that FIPUG has not proven anything that should cause this Commission to withhold or delay Tampa Electric's recovery of prudently incurred costs.

Q. Please respond to FIPUG's fourth recommended action having to do with an investigation of Tampa Electric's affiliate transactions.

A. FIPUG's fourth recommended action is perhaps the most unusual of them all. FIPUG asserts that "the Commission should conduct a more thorough investigation of TECO's affiliate transactions and its procurement of power for wholesale customers." Mr. Pollock follows this statement with, "[S]pecifically, Mr. Collins has observed that TECO has purchased low-cost power at wholesale and directly allocated this purchase to wholesale customers." Finally, Mr. Pollock suggests, "[T]he issue to be resolved is whether this practice and TECO's affiliate transactions are both prudent and beneficial to retail customers."

I cannot understand Mr. Pollock's demands given the lack of evidence provided in his testimony. All affiliate wholesale power transactions are cost-based, as required by the FERC. Tampa Electric and its affiliates have requested and received approval from FERC for its two wholesale energy transactions: 1) the purchase of Hardee power plant capacity and energy, and 2) the sale of a portion of Big Bend Unit 4. In addition, these transactions were reviewed and approved by this

Commission.

Q. Should the Commission consider Mr. Pollock's invitation to "delay and investigate"?

A. Absolutely not. Mr. Pollock's efforts in this regard are groundless. FIPUG's position via Mr. Pollock's testimony has not changed. The Commission has seen this position served up by FIPUG in numerous recent proceedings and has rightly rejected these tactics. FIPUG, in general, and Messrs. Pollock and Collins, in particular, offer no justification whatsoever for a different result here.

Q. Does this conclude your testimony?

A. Yes it does.

BY MR. BEASLEY:

Q Ms. Jordan, did you also prepare the Exhibit JDJ-4 that accompanies your rebuttal testimony?

A Yes.

Q Thank you. Could you please summarize your rebuttal testimony.

A Good morning. My rebuttal testimony addresses the inaccuracies in the testimony of Mr. Jeffry Pollock testifying on behalf of FIPUG, as well as his unfounded allegations of delays and reluctance on the part of Tampa Electric in providing FIPUG with information. In addition, I take issue with FIPUG's recommended actions.

First, Tampa Electric does not favor its wholesale customers at the expense of retail customers as Mr. Pollock stated. Mr. Pollock fails to realize or acknowledge that currently, with the exception of one unit power sale, all other separated sales are charged system average fuel costs, which include not only the system average fuel cost for Tampa Electric's own generation, but the cost of purchased power as well. Both Mr. Pollock and his colleague, Mr. Collins, are simply wrong in their conclusion that 100 percent of the cost of purchased power is borne by retail ratepayers and that wholesale customers are directly benefiting from the company's lowest cost generation.

Secondly, Tampa Electric has provided everything

FIPUG requested. On three separate occasions, the company offered to supply FIPUG with highly confidential and competitive information the company had objected to if FIPUG would sign a nondisclosure agreement. Tampa Electric is not responsible for any delay resulting from FIPUG's inaction.

Third, Tampa Electric is complying with Order Number PSC-97-0262-FOF-EI in Docket Number 97001-EI (sic) which requires that separated sales on a prospective basis be credited at average system fuel costs. Therefore, the company agrees with Mr. Pollock's first recommended action.

FIPUG's second action that a separate docket be open to address the company's management of its long-term wholesale contracts is completely unwarranted. Between the information the company has provided both to FIPUG and the Commission staff, the review of Tampa Electric's long-term separated wholesale contracts by the Commission and by the FERC and the detailed audits this Commission has performed, there is simply no justification for the creation of a separate docket.

FIPUG's third recommendation to hold -- action to hold Tampa Electric's fuel and purchased power true-up in abeyance pending the outcome of any separate new docket is not justified. This is an ongoing docket, and all of FIPUG's assertions have been reviewed and continue to be reviewed by this Commission. FIPUG has not revealed anything new, and this Commission has already exhaustively reviewed the company's fuel and purchased power activities. The bottom line is that FIPUG has not proven anything that should cause this Commission to withhold or delay Tampa Electric's recovery of prudently incurred costs.

Finally, FIPUG's fourth action having to do with an investigation of Tampa Electric's affiliate transactions is baseless. Mr. Pollock's testimony put forth no evidence to support such an action. All affiliate wholesale power transactions are cost-based as required by FERC. Tampa Electric and its affiliates have requested and received approval from FERC for its two wholesale energy transactions. In addition, these transactions were reviewed and approved by this Commission.

Thank you. That concludes my summary.

MR. BEASLEY: Ms. Jordan is available for questions.

MR. VANDIVER: No questions.

CHAIRMAN JACOBS: Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Jordan, you stated that currently with the exception of one unit power sale, all other separated sales are charged average system fuel costs which includes not only fuel costs of Tampa Electric's own generation but the cost of purchased power as well; is that correct?

A That is correct.

Q And those costs are contained on Line 29 of your Exhibit E?

A Are you referring to E1 --

Q Yes, ma'am.

A -- Schedule E1?

Q E1, yes, I'm sorry.

A Yes.

Q That's correct?

And the system average fuel cost that the wholesale customers pay for the forecasted year will be $27.85 a megawatt hour?

A What they will actually pay -- so that I make this clear, the two seven eight that is shown there is backed into because this is from the FPSC jurisdiction perspective. So the actual adjustment factor that the wholesale customers will pay is shown on my exhibit on JDJ-4. There are minor adjustments because it's FERC jurisdiction that we have to account for. So the actual fuel adjustment average is 27.34.

Q So it's lower than the --

A Just slightly lower.

Q That's lower than the system average as it applies to the retail customers, which is on Line 28?

A No. If you go back to -- I've already applied line losses on the 27. It's actually 28.02 before line losses, which is -- also would be equivalent to where we're looking at on the system that is prior to the line losses being applied.

Q On Line 40, retail customers are not going to be charged $27.30. They're going to be charged $33.01 a megawatt hour?

A That is correct.

Q But you don't charge that to your wholesale customers because it includes other things such as GPIF reward?

A It also includes -- so that you can get a clear indication of how this works, the E1 Schedule that is shown here also includes the true-up, like for 2000. The wholesale customers are currently paying their portion of the 2000 true-up currently. They do not have a final true-up. Every month we know what their actual under/overrecovery is. So when we get to the end of December, for example, of 2000, January 2001, we actually apply the underrecovery at that point in time. So they're paying their true-up earlier than the retail customer. The retail customer isn't seeing the underrecovery for 2000 until the 2002 factor is set.

Q I see. Will their payment be as much as $33?

A I don't know exactly what it is, but they are paying their pro rata share.

Q And that's not all wholesale customers, is it?

A That's everything except for the Big Bend 4 sale. That's -- all of our separated AR-1 customers are paying that price.

Q Except for the sales to your affiliated company, Hardee Power Partners?

A The Big Bend 4 sale.

Q Yes. And except for the Schedule D sales that are listed on Line 13 of your Schedule E1 --

A Yes, that's the nonfirm sale that we spoke of yesterday.

Q And so that won't happen -- I mean, they won't pay --

A Those sales are being made in order to reduce the cost. If those sales were not there, those separated sales were not there, then they would be back into the retail jurisdiction.

Q All right. Now, you mentioned Line 13 where under contract with Seminole you'll receive $14.68 a megawatt hour. And do you know the details of that contract?

A I don't know the details, but that is the contract that I was referring to yesterday that is wheeled through Seminole to Peace River to a nonfirm customer.

Q Right. And that nonfirm customer is IMC?

A I would say yes.

Q Does IMC pay $14.68, or does it pay some higher amount of money each month?

A I don't know what they pay because there are probably wheeling charges that are associated, but I'm assuming as far as the fuel, that's what they're seeing for their fuel charge.

Q Who does IMC pay? Do they pay PreCo (phonetic), or do they pay you?

A I think they pay PreCo.

Q And do they pay under the IS-1 tariff to --

A For the fuel.

Q For the fuel and for the capacity, or they don't have to pay --

A I don't know those terms, sir. That's what I was saying. I don't know the details of that contract to tell you that.

Q So under the contract you negotiated with Seminole, how did you come up with that $14.68?

A I didn't personally get involved in that, so I don't know the details. But I know it is predicated on the IS-1 tariff.

Q Is there any testimony in this proceeding that deals with those details or explains it or shows the benefit to retail customers of that sale?

A Not that I'm aware of.

Q And did the full audit of the Public Service Commission that you referred to go into that sale? Do you know?

A I don't know.

Q I see. Now, the sale of the affiliated company, Hardee Power, of the Big Bend capacity, you say those costs --

it's at cost, and the costs were approved by FERC. And Mr. Brown didn't know whether this Commission had any authority to deal with the costs provided in that contract. He referred that question to you. Do you know what authority, if any, this Commission has to change the cost that Hardee Power is required to pay Tampa Electric Company?

A I don't know exactly what the Commission's authority is, but I would say that having reviewed the contracts and the terms and approved it, I would say that they have set forth policy, and there is nothing that's been put forth that would dictate changing that. The sale has been separated from the rate base. The retail customers have benefited from that. It's currently in existence. It is reducing the overall cost as far as the system average fuel costs go.

Q How does that happen? How does it reduce the overall cost as far as system?

A Because by having those sales there, once you take your generation and your purchased power, then you're backing out what you're making on the sale, so you're lowering the overall fuel cost.

Q Well, I don't quite understand that.

A Well, when you look at Line 24 of the E1 Schedule that you always refer to, that is taking the generated power plus the purchased power and backing out the fuel cost of the gains and the power sales; and, therefore, you're reducing that total line.

Q Well, how about Line 15? Isn't that what Hardee Power pays for fuel cost?

A Yes.

Q And how is -- that's $25.62?

A Yes.

Q And for the first eight months of this year, in order to purchase power because Big Bend was unavailable to retail customers, you paid $105 a megawatt hour for power.

A Are you referring -- when you say "Big Bend was unavailable," it was separated out from the rate base --

Q That's right. It's unavailable to retail customers.

A -- so they are paying for their slice of the system. So, yes, it was unavailable and since that it's been separated out, but the customers have gotten that benefit by the fact that their base rates were lowered.

Q And so their base rates are lowered by the component of --

A They are not paying for the asset.

Q I beg your pardon?

A They are not paying for that asset, that portion of the asset.

Q I see. And that was separated out at average system cost back in 1989, was it?

A I don't know the date, but, yes, we talked about that yesterday.

Q And you've done no current studies to determine if retail customers are benefiting still today from that transaction?

A As I talked yesterday, no, we haven't, and I'm not real clear at this point what type of a study you're referring to.

Q I'm asking if you've done any study to determine if retail customers are receiving benefits from this 1989 sale to your affiliated company.

A And I guess I would still have to go back to the point that I pointed out earlier, which is, is that as long as they are not seeing those costs in the retail rate base, they are benefiting because they are paying a lower price in base rates.

Q Their base rates are lower?

A Right.

Q But if that plant were available to the retail customers, their fuel cost would be $25.62 instead of the $105 that they're currently paying in so far as the capacity from that 145 megawatts is concerned, wouldn't they?

A I don't know where you got the 105 but --

Q Well, were you listening when I was asking the questions of Mr. Brown?

A Yes.

Q And Mr. Brown said that the first eight months of this year you paid $32 million for purchases from other customers and all that is charged to the retail customers.

A Yes.

Q Is that inaccurate?

A No. I wasn't questioning the 32 million.

Q And did you question the calculation that showed that you're paying for those purchases $105 a megawatt hour?

A I didn't personally do those, so that's what I was saying.

Q But if Big Bend 4 had been available for the retail customers, what would their share of the fuel cost be for that plant?

A I assume it would be the 25.62 that you're referring to, but what I'm saying is, I don't know what the impact would have been to base rates had that been in the rate base for all these years --

Q You don't know --

A -- because there is a point where that turns so that there were probably times where the fuel costs were lower. We've had some things that have happened in recent years, but I can't say on the whole that they would not still be benefiting by the fact that it would be in rate base.

Q I see. And you haven't done any study recently to determine if they're still benefiting?

A No. I think I made --

Q Are you aware of any study that's been done since 1989?

A I have a very short history, so I can't tell you with certainty that there hasn't been an analysis performed. I have just not done that in my tenure.

Q Is there any plan to do an analysis to determine if retail customers are benefiting?

A Not that I'm aware of.

Q And if it was determined that they're not benefiting currently, could the Florida Public Service Commission do anything about it under your understanding?

A My understanding would probably be that we would still need to follow the terms and conditions of the contract.

Q So you would be obligated to your affiliated company to continue to sell at $25 fuel costs, and if you wanted to meet your firm customers' needs, you would have to buy electricity elsewhere?

A Yes. I don't see this any different than if we had a QF contract. I don't know if affiliate makes it really any different. It's a contract that was signed based on the information known at the time. It was justified based on the projected savings at the time, and therefore, you would honor that contract regardless of it being an affiliate transaction or not.

Q But that was, at the time, in 1985, and you entered into a long-term contract that binds your retail consumers for many, many years, didn't you?

A Yes.

Q And is it your testimony that today's Commission is bound by the decisions made my Commissioner Lauredo and --

MR. BEASLEY: Objection. That calls for a legal conclusion.

MR. McWHIRTER: Good. I accept the objection.

CHAIRMAN JACOBS: I guess that means it's sustained.

BY MR. McWHIRTER:

Q Ms. Jordan, you attached an exhibit to your testimony called JDJ-4 that refuted the testimony supplied by Collins and Pollock; is that correct?

A That is correct.

Q And what is the period of your analysis for that study?

A This isn't an analysis. It is just simply the calculation, the same way we do a projection for the retail fuel factor. This is for the period January 2002 through December 2002. It's the AR-1. It is what we will charge the separated wholesale customers.

Q I see. So was the Collins and Pollock study for the year 2002 and -- December 2002 -- let me restate that question.

Was the Pollock study for the period January to

December 2002, or was it for some other period?

A It was some other period, but regardless, this is the calculation that we use every year when we do the adjustment fuel factor for the separated wholesale sale. And to make a straight comparison, my testimony, my direct testimony, dealt with the 2002 projected year. So to keep it in comparison so that we could show that the costs that we're utilizing are one and the same, I showed you the calculation for 2002.

Q So this does not refute their schedule. It only refutes one they might have done for the period January 2002?

A It refutes their claim that the wholesale customers are not paying their fair share. It refutes their claim that retail customers are paying 100 percent of the purchased power when you consider the fact that the total fuel and net power transaction costs that I start out with are the system costs that are identical to the retail rate base.

Q It's possible you could have cleaned up your act since 1998 when they did that study, isn't it? You don't know because you didn't do the study, did you?

A There's so much in what you just said that I won't even attempt to answer it that way.

Q All right.

A It implies that we had something to clean up, so --

Q But -- well, I won't dwell on that any further.

You said that your company supplied everything that

FIPUG requested.

A That's correct.

Q And you were personally in charge of accumulating and delivering everything?

A Yes, sir. I think we delivered you about 1,300 pages of interrogatory responses and over 6,000 pages of production of documents the first part of the year.

Q And that, of course, included giving FIPUG copies of things that you'd given to the Public Service Commission staff, and those weren't FIPUG requests for the 6,000 pages, were they?

A One of those.

Q Oh, one of them?

A Yes.

Q They had one request for 6,000 pages?

A No. One of the things we provided to you was a staff request.

Q Okay. So you're not saying then that FIPUG requested 6,000 pages. You're saying that you gave FIPUG something you had given to somebody else, and you counted that in determining how much was given to us?

A There is a portion in there, yes, that you requested to be served copies of.

Q On August the 21st, FIPUG requested some information. Do you know when that information was supplied?

A You would have to be more specific than that. You all served quite a number of interrogatories to us, sir.

Q We gave you interrogatories numbered 58D, 58F, and 59. Did you prepare the response --

A I did not prepare those personally, but I think that's what we provided yesterday as a result of the order that was provided -- that was --

Q So in response to the August 21st FIPUG request, you supplied the information on the first day of the hearing, November 20th?

A We had the information prepared. We objected to it on a confidential basis, if I remember those questions correctly.

Q You refused to give it because you felt -- you refused on the basis of giving it to the attorneys would poison the minds of the attorneys when they were advising their clients. Wasn't that the basis of your objection?

MR. BEASLEY: Objection. That was not in any objection, the poisoning the minds. I think that's ridiculous. I object --

MR. McWHIRTER: My mind is equally poisoned.

MR. BEASLEY: -- on the grounds that it's ridiculous.

BY MR. McWHIRTER:

Q What was the basis of the objection?

A As I said, I think it was -- if I'm remembering correctly, those questions were dealing with highly confidential information that we felt that there was enough precedent there that we had not provided that information previously and we objected to that. Once the Prehearing Officer ruled and you all requested that we immediately respond, we provided the information. That order came out, I think, on Monday, November the 19th, and we responded promptly.

Q And the information requested was what you paid to an affiliated company for coal back in 1998; is that correct?

A Subject to check, I will agree to that. I really don't remember the question specifically.

Q And what you paid to your affiliated company for coal in 1998 you considered to be highly confidential and prejudicial. How is that -- what's the basis for that?

A I'm really not the fuel expert person, so I really don't want to overstep boundaries with regards to confidential treatment of fuel information.

Q I see. So that person -- no one here today, neither you nor Mr. Brown, have that information, do you?

A That's correct. It's my understanding that I think you said you had no questions of our fuel witness in this docket.

Q So if this proceeding were continued so that people could look into your affiliate transactions, we would be able to plumb that circumstance, would we not?

A This is an ongoing docket, and it's my understanding that you have every day of the year basically to look into the matters. I know there's a point where discovery closes prior to the hearing, but then, you know, it kicks right back in. So I'm not really sure what you're asking.

Q But in the meantime, you have an $88 million true-up, and you want to continue to collect the money for the true-up even though the matter hasn't been fully explored because the information wasn't available; is that correct?

A I would disagree with you on that. One, the analysis that your consultants utilized or did, the information was available, especially the A Schedules. That's in the public domain. We did not withhold the information, and basically everything is subject to true-up within this docket. And really, by holding this back and it turns out that you find nothing, it's really to the detriment of the ratepayers. They will either end up with higher factors, or they will pay for the underrecovery because there's interest being charged on that. So I'm not sure that you really accomplish much by delay.

Q Well, what is the interest at the current commercial paper rate? Two percent a year?

A Yes. It has been dropping, but when you consider the amount of the underrecovery, those are still significant dollars in my mind, Mr. McWhirter.

Q $88 million --

A Yeah, $88 million.

Q -- times one-twelfth of 2 percent if it were continued for one month for further study or two-twelfths of 2 percent if it were continued two months; is that correct?

A But you're also delaying the amount of megawatt hours that you're spreading those dollars over now, so it's going to be more impact in terms of the factor because the factor will increase more.

Q But you would still get that plus interest anyway, wouldn't you?

A That's correct, but I would wonder why you'd want to subject customers to even further increase.

Q Well, it might be that fuel costs go down and your purchase price goes down, and they would benefit --

A Well, like you, I'm confident in our analysis, so --

Q Yeah, but you haven't done any study since August, have you?

A No, but the underrecovery is an actual underrecovery that is there now.

MR. McWHIRTER: I have no further questions.

CHAIRMAN JACOBS: Staff.

MR. KEATING: Staff has no questions.

CHAIRMAN JACOBS: Commissioners.

COMMISSIONER DEASON: Yeah. I have a question that was referred to you concerning the calculation of system average fuel cost. Could you help me on how that is done?

THE WITNESS: Sure. On the E1 -- it may be easier just to look at the E1 Schedule. The system average fuel cost really is the Line 5 component, which is our cost for our generation plus the cost for purchased power, which is on Line 11, and then any nonseparated nonfirm sale as well as any sale that has been approved for special treatment such as the Big Bend 4 sale, those costs are backed out. That's a credit to the clause. So you come to Line 24, which is our total fuel and net power transactions, and that's that $524.987 million divided by the total megawatt hours, and that's the system average fuel cost that we would utilize.

And as you can see on my Exhibit JDJ-4, that 524 million, that number is the same number that we start out with for the wholesale customers. Then we have to tweak it a little bit for FERC jurisdictional issues and divide that by the megawatt hours, and that's how we come out with the wholesale system average fuel costs. So they are paying a share of our generation as well as a share of the purchased power costs.

COMMISSIONER DEASON: Okay. Now, is there some type of true-up associated with that?

THE WITNESS: Yes. Every month when we do month-in, we know what the actual costs are for all of these pieces, and based on what the system average number comes out to be, we multiply that by the megawatt hours for the wholesale customers, and we keep track every month of what the wholesale customer under/overrecovery is. And as you know with the retail customers, we normally do an actual estimated filing, and we project where we think we're going to end up at the end of the year.

With the wholesale customers, we don't do that. So when we get to the end of the year, we actually know what their under/overrecovery is. So on their bill starting that next year, they will see that amount divided by 12, and we charge interest, and so they pay their true-up. So they are currently paying their 2000 true-up in 2001. Unlike the retail jurisdiction which will pay their 2000 true-up in 2002. So they see theirs more real time, so to speak.

COMMISSIONER DEASON: Okay. The sales that take place out of Big Bend 4, the Hardee Power Partners sale --

THE WITNESS: Yes, sir.

COMMISSIONER DEASON: -- those sales are done at system average or not?

THE WITNESS: No, those were allowed special treatment. So it's a unit power sale. So the fuel charges charge the actual fuel cost for the Big Bend 4 unit.

COMMISSIONER DEASON: Okay. Now, what are some of your transactions which are at system average, wholesale transactions?

THE WITNESS: Those would be like all the cities that -- City of Fort Meade, City of Wauchula, Reedy Creek.

COMMISSIONER DEASON: So at the time -- now, are those contracts, do they have options to -- is it like an ongoing transaction, or is it like they notify you that they need "X" megawatts for the next three --

THE WITNESS: These are all requirements customers, so we are serving that load.

COMMISSIONER DEASON: Just as if they were retail?

THE WITNESS: Just as if they were retail. They're treated just like the firm retail customer.

COMMISSIONER DEASON: And right now the only -- the Big Bend -- sale out of Big Bend 4 to Hardee Power Partners, that's the only one that is not at system average?

THE WITNESS: That is correct.

COMMISSIONER DEASON: And that's because it was approved as such during a need determination?

THE WITNESS: That is correct.

COMMISSIONER DEASON: Okay.

CHAIRMAN JACOBS: I have a couple of questions. I think Mr. Brown in his testimony indicated that in the event that that unit power -- that that unit is down, that that contract is met by power services going out to the market itself?

THE WITNESS: That's my understanding, that it is up to the client to go and find replacement service for that.

CHAIRMAN JACOBS: And how is that handled in the scope of this kind of place? Do you know?

THE WITNESS: It wouldn't be reflected within here. They would actually pay that separately.

CHAIRMAN JACOBS: Okay. The -- kind of like an underlying theme of questions from FIPUG is that wholesale customers are going to gain the benefit of either a favorable unit power sale transaction or cost basis under FERC. And the flip side of that is that retail customers then might have a difficulty seeing the benefits of a favorable wholesale market; i.e., if there is a favorable wholesale market, then your practices would seem to indicate that the benefits of that favorable market are going to flow most prominently to wholesale customers simply because they're seeing cost-based contracts and/or unit power sales.

THE WITNESS: The cost-based contracts, however, include the cost for purchased power. So the full requirements customers that we're talking about, they are paying the same basically system average fuel costs that a retail customer sees. So when we have to go to the market for purchased power, that is not being allocated solely to the retail customers. All of the customers that are paying system average fuel, pay for purchased power.

CHAIRMAN JACOBS: Okay. So if there is a favorable wholesale market, that will be reflected in your system average costs?

THE WITNESS: Yes.

CHAIRMAN JACOBS: Okay. And if there are units -- in the event that -- I guess you just answered this question, which I think was implied by Mr. Collins. If you have a high percentage of down capacity, planned or unplanned, which then under his analysis would require you to go to the market more prominently, and in the instance of an unfavorable market, in that instance, he argues that the wholesale customers will see your least cost supply first and then all turn to the retail side. And I don't want to argue for or against his proposition.

My point is this, in the event that you have and I think his numbers are 25, 30 percent outage at a particular point in time, and there are transactions that are occurring on the wholesale side, there is -- and I'll allow for your response to this -- there is the idea that your wholesale operation is essentially benefiting while your overall system is not operating at its highest level, i.e., that you are still getting this revenue benefit from the wholesale side while you have a pretty significant outage issue. Do you understand my point?

THE WITNESS: If I understand correctly,

Commissioner, in that situation, the customers that are full requirements customers, they are going to experience whatever the retail customers experience. So if we are in a favorable wholesale situation where we are purchasing and it is -- even if it's cheaper than our own generation and we purchase even more for economic reasons, everybody benefits because the overall system fuel cost is less.

If we were in an unfavorable situation, then the cost is going to go up and everybody is going to be charged that because they are paying system average fuel costs. So it's not as if we are allocating a cheaper resource first. I mean, when you look at the numbers and you look at my exhibits, the point that we're showing is, is that we end up with one system fuel cost number, and then we come up and divide that by the number of megawatt hours. And the AR-1 customers, those fuel requirement customers, pay that system average fuel price. They are treated just like a firm retail customer, so they have no benefit advantage.

CHAIRMAN JACOBS: And, finally, your unit power sale agreements, as I understand it is the case, you have not entered into another of those, and the two here are terminating in the next two years; is that correct?

THE WITNESS: That is my understanding.

CHAIRMAN JACOBS: And what will happen with those contracts in terms of supplying them after that? Would they be re-upped, or would they go into some other -- do you have any prediction on that?

THE WITNESS: I don't know that.

CHAIRMAN JACOBS: Okay. Thank you.

Redirect.

MR. KEATING: Mr. Chairman, if I could, I had just a couple of questions that I had forgotten about --

CHAIRMAN JACOBS: Okay.

MR. KEATING: -- if staff could ask. This will be real quick.

CROSS EXAMINATION

BY MR. KEATING:

Q There were three interrogatory responses that were referenced in Mr. McWhirter's cross-examination, 58D, 58F, and 59 that TECO just provided yesterday. Do you have those with you?

A I do not.

Q Okay. Is it your understanding -- and I'll just ask you perhaps, subject to check, if you would agree that 58D asks for TECO to provide any price indices to which coal contracts were tied for the period 1998 to 2001?

A Yes.

Q And 59 -- I'm sorry, 58F asked for the monthly cost in dollars per ton for coal delivered to TECO under contracts in place or entered into between '98 and 2001?

A Yes.

Q And Interrogatory Number 59 requests that TECO provide the date of purchase, the amount purchased in tons, cost of the coal, and the unit for which TECO purchased coal for any of the purchases that TECO made on the spot market for '98 to 2000?

A Yes.

Q Okay. How does that coal pricing of coal contract information relate to Issues 21C and D that are stated in the prehearing order concerning TECO's wholesale transactions?

A I don't think it relates to that.

Q Okay. Do you believe that that information relates to 21G -- Issues 21G or 21H in any way?

A I think those were the issues sponsored by Witness Joann Wehle, and it would relate to those issues.

Q I'm sorry, 21G and 21H. Issue 21G is, does TECO currently allocate 100 percent of purchased power cost to retail customers?

A Oh, okay. I don't think it relates to those issues.

Q Okay. And 21H was: Should TECO's separated wholesale sales be charged average system fuel costs and should nonseparated sales be charged system incremental costs?

A No, it doesn't relate to that at all.

MR. KEATING: Thank you.

CHAIRMAN JACOBS: Redirect.

MR. BEASLEY: Just a short redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Jordan, are you aware whether the Commission reviews Tampa Electric's dealings with its affiliates?

A Yes.

Q On a regular basis?

A Yes.

Q Coal and coal transportation?

A Yes.

Q That's scrutinized on a regular basis?

A Yes, it is.

MR. BEASLEY: Thank you.

CHAIRMAN JACOBS: Mr. Beasley, did we identify the exhibit attached to the rebuttal?

MR. BEASLEY: I'm sorry, sir?

CHAIRMAN JACOBS: Did we identify the exhibit attached to the rebuttal?

MR. BEASLEY: I don't believe we did.

CHAIRMAN JACOBS: Let's identify that as Exhibit 11.

(Exhibit 11 marked for identification.)

MR. BEASLEY: And I would move admission of that exhibit.

CHAIRMAN JACOBS: Without objection, show Exhibit 11 is admitted.

(Exhibit 11 admitted into the record.)

CHAIRMAN JACOBS: Thank you. You're excused, Ms. Jordan.

THE WITNESS: Thank you.

MR. BEASLEY: Thank you.

(Witness excused.)

CHAIRMAN JACOBS: We'll take a break and come back in 15 minutes.

COMMISSIONER PALECKI: Mr. Chairman, could we poll the parties to kind of get an estimate of what time we're looking at?

CHAIRMAN JACOBS: Very well. We have basically Power and Light's witnesses up, so I guess, Mr. McGee.

MR. McGEE: I think Mr. Portuondo is --

CHAIRMAN JACOBS: Oh, I'm sorry. You do have a witness, Mr. Portuondo.

MR. McGEE: Yes. All of his issues have been stipulated to. He's here to support the company's position on the two new issues that regard the cost of security and revised sale forecast. I expect little time --

CHAIRMAN JACOBS: Is there cross of Mr. Portuondo?

MR. KEATING: Staff has about maybe five minutes of cross for Mr. Portuondo.

CHAIRMAN JACOBS: Mr. Badders.

MR. BADDERS: Gulf Power is still -- there is still one witness shown for Gulf Power, Terry Davis. I believe that's in error. All of her issues are stipulated. So I believe she can go ahead and just be moved into the record.

CHAIRMAN JACOBS: Okay. Let's see. What about the witnesses for Power & Light, Mr. Hartzog, Ms. Dubin, and Mr. Green? Do you anticipate significant cross?

MR. McWHIRTER: Yes, but only a couple of questions.

CHAIRMAN JACOBS: For each of those?

MR. McWHIRTER: Yes, sir.

CHAIRMAN JACOBS: Okay. Staff.

THE STAFF: Staff may have about 15, 20 minutes for Ms. Dubin.

CHAIRMAN JACOBS: Very well. We'll kind of circle it when we return.

Mr. Vandiver.

MR. VANDIVER: OPC has spoken with staff and deferred their cross to staff.

CHAIRMAN JACOBS: Okay. Very well. It sounds like we have about an hour, an hour and a half. Fifteen minutes, we will be back.

(Brief recess.)

CHAIRMAN JACOBS: We'll go back on the record.

Mr. McGee.

MR. McGEE: Florida Power calls Mr. Portuondo.

JAVIER PORTUONDO

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

DIRECT EXAMINATION

BY MR. McGEE:

Q Would you state your name and business address for the record, please.

A My name is Javier Portuondo. My address --

CHAIRMAN JACOBS: Is your microphone on?

THE WITNESS: Yes, it's on.

CHAIRMAN JACOBS: Okay.

THE WITNESS: My name is Javier Portuondo. My address is P. O. Box 14042, St. Petersburg, Florida.

BY MR. McGEE:

Q Mr. Portuondo, did you submit for this hearing today three sets of direct testimony, one for the true-up of 2000 fuel adjustment costs submitted April 2nd, an estimated actual true-up of 2001 submitted August 20th of this year, and 2002 projection testimony submitted September 20th of this year?

A Yes, I did.

Q And if you were asked the questions that were contained in each of those sets of testimonies, would your answers be the same today?

A Yes, they would.

Q Did you also prepare or supervise the preparation of two exhibits to each of those three sets of testimony?

A Yes, I did.

Q And do you have any additions or corrections that you need to make to those exhibits?

A No, I do not.

MR. McGEE: Mr. Chairman, we'd ask that Mr. Portuondo's direct testimonies be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Mr. Portuondo's testimonies are entered into the record as though read.

MR. McGEE: And I'd ask that his three sets of exhibits be marked for identification. If you wanted to make that as a composite exhibit, that would be satisfactory to us.

CHAIRMAN JACOBS: Very well. Show that marked as Composite Exhibit 4 --

MR. McGEE: Those composite exhibits --

CHAIRMAN JACOBS: I'm sorry, not 4, 12. Composite Exhibit 12.

(Exhibit 12 marked for identification.)

MR. McGEE: Okay. Just to be clear, those exhibits are not fully reflected in the exhibit list in the prehearing order. The exhibits consist of a true-up variance analysis and Schedules A1 through A13 for the true-up testimony. The estimated actual testimony consists of forecast assumptions and cost recovery factors and Schedules E1 through E9. And for the projection testimony, it consists of forecast assumptions and fuel cost factors and Schedules E1 through E10 and H1. I just wanted to make sure that was clear because two of those exhibits were not reflected in the --

CHAIRMAN JACOBS: We do have the complete set for the record -- for the court reporter?

MR. McGEE: Yes, we do.

FLORIDA POWER CORPORATION
DOCKET NO. 010001-EI

Fuel and Capacity Cost Recovery
Final True-up Amounts for
January through December 2000

DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is P. O. Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation (FPC or the Company) in the capacity of Manager, Regulatory Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida in 1992 with a Bachelor's Degree in Business Administration, majoring in Accounting. I began my employment with Florida Power in 1985. During my 16 years I have held various staff accounting positions within Financial Services in such areas as: General Accounting, Tax Accounting, Property Plant & Depreciation Accounting and Regulatory Accounting. In 1996 I became Manager, Regulatory Services. My present responsibilities include the areas of fuel and purchase power cost recovery filings, capacity cost recovery filings, energy conservation cost recovery issues, earnings surveillance reporting, rate design and cost of service issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's Fuel Cost Recovery Clause final true-up amount for the period of January through December 2000, and the Company's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared a three-page true-up variance analysis which examines the difference between the estimated fuel true-up and the actual period-end fuel true-up. This variance analysis is attached to my prepared testimony and designated Exhibit No. ___ (JP-1). Also attached to my prepared testimony and designated Exhibit No. ___ (JP-2) are the Capacity Cost Recovery Clause true-up calculations for the January through December 2000 period. My third exhibit presents the revenues and expenses associated with the purchase of the Tiger Bay facility approved in Docket 970096-EQ and the corresponding amortization. This presentation is also attached to my prepared testimony and designated Exhibit No. ___ (JP-3). In addition, I will sponsor the applicable Schedules A1 through A9 for the period-to-date through December 2000, which have been previously filed with the Commission, and are also attached to my prepared testimony for ease of reference and designated as Exhibit No. ___ (JP-4).

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

FUEL COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2000 for fuel cost recovery?

A. The actual ending balance as of December 31, 2000 for true-up purposes is an under-recovery of $84,596,026.

Q. How does this amount compare to the Company's estimated 2000 ending balance included in the Company's projections for the calendar year 2001?

A. The estimated 2000 ending balance was an under-recovery of $55,217,807. Half of this amount, or $27,608,904, was included in the 2001 projections and is being collected from customers through FPC's currently effective fuel cost recovery factor, with the remainder deferred for recovery in 2002. When the ending balance is compared to the actual year-end under-recovery balance of $84,596,026, the final true-up attributable to the twelve-month period ended December 31, 2000 is an under-recovery of $29,378,219. FPC was granted a mid-course correction to its fuel and purchased power cost recovery factors effective March 29, 2001. The final true-up amount of $29,378,219 was included in the mid-course filing and will be collected in 2001.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional under-recovery of $84,596,026 as shown on your Exhibit No. __ (JP-1)?

A. The factors contributing to the under-recovery are summarized on Sheet 1 of 3. The actual jurisdictional kWh sales were higher than the original estimate by 258,589,546 kWh. This increase in kWh sales, attributable to higher customer growth and a stronger economy, together with a mid-course correction increase in the fuel adjustment factor effective June 15, 2000, resulted in jurisdictional fuel revenues exceeding the forecast by $66.4 million. The $149.0 million unfavorable variance in jurisdictional fuel and purchased power expense was primarily attributable to higher than projected oil and natural gas prices.

When the differences in jurisdictional revenues and jurisdictional fuel expenses are combined, the net result is an under-recovery of $82.6 million related to the January through December 2000 true-up period. Another factor not directly related to the period is an interest provision of

$2.0 million. This results in an actual ending under-recovery balance of $84.6 million as of December 31, 2000.

Q. Please explain the components shown on Exhibit No. ___ (JP-1), Sheet 2 of 3 which produced the $155.8 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 2 of 3 shows an analysis of the system variance for each energy source in terms of three interrelated components; (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH).

Q. What effect did these components have on the system fuel and net power variance for the true-up period?

A. As can be seen from Sheet 2 of 3, variances in the amount of MWH requirements from each energy source (column B) combined to produce a cost increase of $20.1 million. I will discuss this component of the variance analysis in greater detail below.

The heat rate variance for each source of generated energy (column C) reflected an unfavorable variance of $2.3 million. This variance was primarily the result of increased peaking unit operation as a component of the Company's generation mix.

A cost increase of $133,327,678 resulted from the price variance (column D), which was caused by a number of sources detailed on lines 1 through 19 of Sheet 2 of 3. The most significant sources were increased oil and natural gas prices. The increase in gas prices on a national level was the result of unusually cold weather and a shrinking inventory. Increased oil prices resulted from higher market demand as electric utilities switched from natural gas-fired generation to oil-fired generation whenever possible.

Q. What were the major contributors to the $20.1 million cost increase associated with the variance in MWH requirements?

A. The primary reason for the unfavorable variance in MWH requirements was that power purchases were greater than estimated. This variance was due to increased system requirements along with the need to offset the higher cost of oil and natural gas generation. The effect that generation mix has on total net system fuel and purchased power cost is another reason for the unfavorable variance in MWH requirements.

Q. Does the period-ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes, Exhibit No. ___ (JP-4) shows other jurisdictional adjustments to fuel expense. Noteworthy adjustments shown in the footnote to line 6b on page 1 of 4, Schedule A2 of this exhibit include recovery of the Company's investment in 11 previously approved combustion turbine gas conversion projects at Intercession City Units P7-P10, Debary Units P7-P9, Bartow Units P2 and P4, and Suwannee Units P1 and P3.

Q. Did FPC's customers benefit during the true-up period from its investment in the gas conversion projects previously approved by the Commission?

A. Yes. The estimated system fuel savings for the period related to FPC's approved gas conversion projects was $11,193,746. The total system depreciation and return was $3,432,593, resulting in a net system benefit to the Company's customers of $7,761,153. A schedule of depreciation and return by gas conversion unit is included in Exhibit No. ___ (JP-1), Sheet 3 of 3.

Q. Does the previously referenced footnote to line 6b on page 1 of 4, Schedule A2 of your Exhibit No. ___ (JP-4) show any other unusual adjustments to fuel expense for the true-up period?

A. Yes. The Company capitalized $0.3 million of fuel associated with the testing of the new Intercession City Units P12-P14 and consequently excluded this amount from fuel expense. The fair value of the remaining fuel burned at those units is reflected within the A Schedules as part of recoverable fuel expense and offset by a corresponding amount of fuel revenue in accordance with Commission Order No. 94-1160-FOF-EI.

Q. Has FPC included any sulfur dioxide emission allowance transactions in fuel expense for the true-up period?

A. Yes, during the true-up period the Company paid $2,173,000 to purchase SO_2 allowances and included $1,986,737 of this amount in fuel expense, leaving an allowance inventory balance of $186,263 at year-end.

Q. Were any other adjustments of note included in the current true-up period?

A. Yes. On January 20, 1997, FPC entered an agreement with Tiger Bay Limited Partnership to purchase the Tiger Bay cogeneration facility and terminate five related purchase power agreements (PPAs). The purchase agreement approved in Docket No. 970096-EQ was executed on July 15, 1997, at which time Tiger Bay became one of FPC's generating facilities. Pursuant with the terms and conditions of the approved stipulation, FPC placed approximately $75 million of the purchase price into rate base, with the remaining amount set up as a regulatory asset for the retail jurisdiction, according to FPC's jurisdictional separation at that time. The stipulation allows FPC to continue collecting revenues from its ratepayer's as if the five related purchase power agreements were still in effect. The revenues collected would then be used to offset all fuel expenses relating to the Tiger Bay facility and interest applicable to the unamortized balance of the retail portion of the Tiger Bay regulatory asset, with any remaining balance used to amortize the regulatory asset.

Following this methodology, a $40.9 million adjustment was made to remove the cost of fuel consumed by the Tiger Bay facility during the true-up period, since these costs were recovered from the PPA revenues. Exhibit No. ___ (JP-3) shows a year-end retail balance for the Tiger Bay regulatory asset of $226,656,451, computed in accordance with the approved stipulation. This balance reflects an additional reduction of $46.5 million from a discretionary accelerated amortization contributed by the Company apart from the fuel adjustment amortization mechanism.

Q. Has the three-year rolling average gain on economy sales included in Florida Power's filing for the November, 2000 hearings been updated to incorporate actual data for all of year 2000?

A. Yes. Florida Power's three-year rolling average gain on economy sales, based entirely on actual data for calendar years 1998 through 2000, is $11,880,954.

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2000 for capacity cost recovery?

A. The actual ending balance as of December 31, 2000 for true-up purposes is an under-recovery of $1,545,753.

Q. How does this amount compare estimated 2000 ending balance included in the Company's projections for calendar year 2001?

A. When the estimated under-recovery of $143,205 to be collected during the calendar year 2001 is compared to the $1,545,753 actual under-recovery, the final net true-up attributable to the twelve-month period ended December 2000 period is an under-recovery of $1,402,548.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission, as set forth on Schedule A2, "Calculation of True-Up and Interest Provision" for fuel cost recovery.

Q. What factors contributed to the actual period-ending under-recovery of $1.5 million?

A. Exhibit No. ___ (JP-2), Sheet 1 of 3, entitled "Capacity Cost Recovery Clause Summary of Actual True-Up Amount," compares actual results to the original forecast for the period. Actual revenues attributable solely to the true-up period were $1.9 million higher than forecast. However, as can be seen from Sheet 1, when the prior period true-up is taken into account jurisdictional revenues were $2.6 million lower, primarily due to a $4.5 million variance between the projected and actual 1999 under-recovery balance. This unfavorable variance was mitigated to an extent by lower net capacity expenses, which were $0.4 million below the forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

FLORIDA POWER CORPORATION

DOCKET NO. 010001-EI

Estimated/Actual Fuel and Capacity Cost Recovery True-Up Amounts for January through December 2001

DIRECT TESTIMONY OF JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation (FPC or the Company) in the capacity of Manager, Regulatory Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from the University of South Florida in 1992 with a Bachelor's Degree in Business Administration, majoring in Accounting. I began my employment with Florida Power in 1985. During my 16 years I have held various staff accounting positions within Financial Services in such areas as: General Accounting, Tax Accounting, Property Plant & Depreciation Accounting and Regulatory Accounting. In 1996 I became Manager, Regulatory Services. My present responsibilities include the areas of fuel and purchase cost recovery filings, capacity cost recovery filings, energy conservation cost recovery issues, earnings surveillance reporting, rate design and cost of service issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2001.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and Commission Schedules E1 through E9, which contain the calculation of the Company's true-up balances and the supporting data. Parts A through C contain the assumptions which support the Company's reprojection of fuel costs for the months of August through December 2001. Part D contains the Company's reprojected capacity cost recovery true-up balance and supporting data.

FUEL COST RECOVERY

Q. How was the estimated true-up under-recovery of $23,640,300 shown on Schedule E1-B, Sheet 1, line 20, developed?

A. The estimated true-up calculation begins with the actual balance of $(61,363,522), taken from Schedule A2, page 3 of 4, for the month of July. This balance was projected to the end of December, 2001, including interest estimated at the July ending rate of 0.315% per month. The development of the actual/estimated true-up amount for the period ending December 2001 is shown on Schedule E1-B.

Q. What are the primary reasons for the projected December-ending 2001 under-recovery of $23.6 million?

A. The primary reason for the projected under-recovery is a forecasted settlement payment of $20 million to Lake Cogen in September 2001.

Q. What is the nature of the Lake Cogen settlement payment?

A. In 1994, Lake Cogen filed suit against FPC regarding the calculation of their energy payment. Primarily the dispute involved the two types of energy pricing calculations allowed in the contract and when each should be applied. The contract allowed for energy to be priced at either the as-available tariff price or the contractually defined price. In April 2001, the Fifth District Court of Appeal ruled that FPC was underpaying Lake Cogen. They concluded that "the contract requires that Lake Cogen be paid the firm energy rate for all hours that the avoided unit operates and that it operates all the time except for periods it is shut down for maintenance and repairs". The $20 million settlement payment is comprised of a $16.4 million recalculation of the billing from August 1994 through June 2001 plus interest of $3.6 million.

Q. How does the current fuel price projection compare with the projection used for the mid-course correction?

A. Forecasted prices for residual fuel oil were the same as used in the mid-course filing. Distillate oil increased $2.90 per barrel, or 8%, from approximately $33.60 to $36.50 per barrel. The natural gas forecast decreased $.85 per MMBTU or 16%, from an average of $5.30 to $4.45 per MMBTU. Coal prices increased from an average cost per ton of $46.50 to over $51.60 or 11%. Rising coal prices also led to increased purchased power expense mainly due to higher projected payments to Qualifying Facilities.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecast was made by the Fuels Supply Department based on forecast assumptions for residual (#6) oil, distillate (#2) oil, natural gas, and coal. The assumptions for the reprojection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the estimated true-up under-recovery of $3,712,132 shown on Part D, Line 25, developed?

A. The estimated true-up calculation begins with the actual balance of $(8,479,436), for the month of July. This balance was projected to the end of December, 2001, including interest estimated at the July ending rate of 0.315% per month.

Q. What are the major changes between the original projection for the year 2001 and the actual/estimated reprojection?

A. The variance between the projected and actual true-up balance at 12/31/00 is responsible for $1.4 million of the estimated $3.7 million true-up under-recovery at 12/31/01. The remainder of the balance is primarily attributable to lower sales.

Q. Does this conclude your testimony?

A. Yes.

FLORIDA POWER CORPORATION

DOCKET NO. 010001-EI

Levelized Fuel and Capacity Cost Recovery Factors January through December 2002

DIRECT TESTIMONY OF JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation (FPC or the Company) in the capacity of Manager, Regulatory Services.

Q. Have the duties and responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of January through December 2002.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data.

FUEL COST RECOVERY

Q. Please describe the levelized fuel cost factors calculated by the Company for the upcoming projection period.

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 2.687 ¢/kWh (before metering voltage adjustments). The basic factor consists of a fuel cost for the projection period of 2.62112 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00072 ¢/kWh, and an estimated prior period true-up of 0.06369 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for secondary, primary, and transmission metering tariffs. To accomplish this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales (forecasted at meter level). This is consistent with the methodology being used in the development of the capacity cost recovery factors.

Schedule E1-E develops the TOU factors 1.216 On-peak and 0.907 Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 2.692 ¢/kWh.

Q. What is the change in the fuel factor from the current April - December mid-course correction period to the 2002 projection period?

A. The average fuel factor decreases from 2.885¢/kWh to 2.692 ¢/kWh, a decrease of 6.7%.

Q. Please explain the reasons for the decrease.

A. The decrease is due primarily to a significant reduction in average natural gas prices compared to those projected for 2001. The projected average price of natural gas decreased from $6.38 per Mmbtu to $4.43 per Mmbtu, or 30.5% from the 2001 mid-course filing. This was the direct result of producers drilling more wells that expanded the supply available to the market, and a decrease in natural gas demand as industrial boilers and power generators switched to oil. In addition, a projected increase in nuclear generation for 2002 will replace the use of higher cost fuels, which contributed to the decrease in the fuel factor. Offsetting these favorable changes is a sharp increase in projected coal prices. During 2001 average coal prices were expected to reach $46.50 per ton, while forecasted prices for 2002 are as high as $61.16 per ton, or a 31.5% increase. Driving this cost increase are such factors as production problems at operating mines, labor pool issues for mining operations, and permitting issues encountered by suppliers.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. Line 4 shows the recovery of the costs associated with conversion of combustion turbine units to burn natural gas instead of distillate oil, the annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities, and the expected cost of purchasing emission allowances for the year. Recovery of the conversion for the peaking units has already been approved by this Commission. The cost of conversions included in line 4 is $1,551,000, the payment to the DOE is $1,683,000, and the emission allowance purchases are estimated to be 38,640 tons at a price of $200 per ton, or $7,728,000. The three items together total $10,962,000.

Q. What is included in Schedule E1, line 6, "Energy Cost of Purchased Power"?

A. Line 6 includes energy costs for the purchase of 60 MWs from Tampa Electric Company and the purchase of 409 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 9 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Florida Power in the form of reduced costs per kW. Both of these contracts have been in place and have been approved for cost recovery by the Commission. The capacity costs associated with these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases (Non-Broker)"?

A. Line 8 consists primarily of economy purchases from within or outside the state which are not made through the Florida Energy Broker Network (EBN). Line 8 also includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, and off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA). The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery clause. Such non-fuel charges, if any, are reported on line 10.

Q. How was the Gain on Other Power Sales, shown on Schedule E-1, Line 15a, developed?

A. Florida Power estimates the total gain on non-separated sales during 2002 to be $4,765,728, which is below the three-year rolling average for such sales of $11,354,219 by $6,588,491. Based on the sharing mechanism recently approved by the Commission in Docket No. 991779-EI, the total gain will be distributed to customers.

Q. How was Florida Power's three-year rolling average gain on economy sales determined?

A. The three-year rolling average of $11,354,219 is based on calendar years 1999 through 2001, and was calculated in accordance with Order No. PSC-00-1744-PAA-EI, issued September 26,2000, in Docket 991779-EI. Actual gains for 1999 and 2000 were based on information supplied to the Commission in the monthly fuel adjustment filings ("A" schedules). The estimated gain for 2001 was supplied to the Commission in Florida Power's Estimated/Actual True-up filing, submitted August 20, 2001, on Schedule E1-B, Sheet 2, Lines 14a and 15a.

Q. Are there any changes to the calculation of the QF contract payments in the 2002 period?

A. Yes, the calculation of Lake Cogen's energy payments has been modified based on the decision of the Fifth District Court of Appeals. In that decision, which overturned the decision of the trial court, the appellate court ruled that Lake Cogen should be paid at the firm energy rate for all hours except for unspecified maintenance periods, during which Lake Cogen is to be paid at the as-available energy rate.

Q. What is the firm energy rate?

A. Under the Lake Cogen contract, the firm energy rate is the product of Florida Power's coal cost at Crystal River 1 and 2 and the contractually defined heat rate, which is then added to the contractually defined variable O&M expense. For example, the firm energy rate in July 2001 was $25.36 per MWh based on a coal price of $1.793 per MMBtu, times the heat rate of 9.83 MMBtu per kWh, plus variable O&M of $7.73 per MWh.

Q. How does the appellate court's energy payment methodology for the Lake Cogen contract used in the 2002 projections compare with the methodology used in the projections for 2001?

A. The previous methodology was based on the ruling of the trial court before it was overturned on appeal. Under the trial court's ruling, Lake Cogen was to be paid at the firm energy rate for the contractually specified on-peak hours and at the as-available rate for the remaining off-peak hours. As described above, the appellate court ruled that Lake Cogen is to be paid at the firm energy rate for all hours except during maintenance periods.

Q. What remains to be done in the Lake Cogen court proceeding?

A. The case was remanded back to the trial court for the entry of a final order consistent with the appellate court's decision. Florida Power and Lake Cogen are currently attempting to negotiate stipulated findings of fact that will be included in the trial court's order on remand. These findings of fact will specify among other things the duration and scheduling of annual maintenance periods, as well as the amount of the retrospective lump sum payment due Lake Cogen for the period from August 1994 to the present, which was estimated to be $20 million through July 2001 in my August 2001 reprojection testimony. The remand order is expected to be entered before the November hearing in this proceeding

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. Florida Power has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1408 MW in 2002. The fuel costs charged to Seminole for supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. New contracts for fixed amounts of intermediate and peaking capacity began in January of 2000. While those sales are not necessarily priced at average cost, Florida Power is crediting average fuel cost for the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis.

Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI. The stratified sales shown on Schedule E6 include 99,863 MWh, of which 93% is priced at average nuclear fuel cost, the balance at an estimated incremental cost of $25 per MWh. Other transactions included on Line 17 are the 50 MW sale to Florida Power & Light and a 15 MW sale to the City of Homestead.

Q. Please explain the procedure for forecasting the unit cost of nuclear fuel.

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (Cycle 13) was developed from the unamortized investment cost of the fuel in the reactor. Cycle 13 consists of several "batches," of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 13 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite cost of Cycle 13 is $0.33 per million BTU.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated.

A. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into the Company's production cost model, PROSYM, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROSYM then computes system fuel consumption, replacement fuel costs, and energy purchases and costs. This data is input into a fuel inventory model, which calculates average inventory fuel costs. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by the forecasting section of the Financial Planning and Analysis Department using the most recent data available. The forecast used for this projection period was prepared in June 2001.

Q. Is the methodology used to produce the sales forecast for this projection period the same as previously used by the Company in these proceedings?

A. Yes. The methodology employed to produce the forecast for the projection period is the same as used in the Company's most recent filings, and was developed with an econometric forecasting model. The forecast assumptions are shown in Part A of my exhibit.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecast was made by the Fuels Supply Department based on forecast assumptions for residual (#6) oil, distillate (#2) oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery (CCR) factor is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors from the Company's most recent Jurisdictional Separation Study available at the time this filing was prepared **(projected through 12/31/01 ??).**

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of July, 2001 and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $(3,712,132) is then carried forward to Sheet 1, to be collected during the January through December, 2002 period.

Sheet 3: Development of Jurisdictional Loss Multipliers. The same delivery efficiencies and loss multipliers presented on Schedule E1-F.

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 2000 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCR factor for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 1, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCR factor for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCR factor.

Q. Please discuss the increase in the CCR factor compared to the prior period.

A. The projected average retail CCR factor of 0.92417 **¢ per kWh ?** is 3.6% higher than the previous year's factor of 0.89218 **¢ per kWh ?**. The increase is primarily due to the annual contractual escalation in capacity payments. Also contributing to the increase is the fact that capacity costs projected for 2001 included a true-up under-recovery of $0.1 million from the prior year, while the projected 2002 costs include a larger true-up under-recovery of $3.7 million.

OTHER ISSUES

Q. Has Florida Power confirmed the validity of the methodology used to determinine the equity component of Electric Fuels Corporation's capital structure for calendar year 2000?

A. Yes. Florida Power's Audit Services department has reviewed the analysis performed by Electric Fuels Corporation. The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support Florida Power business was compared to revenues billed using equity based on 55% of net long-term assets (short cut method). The analysis showed that for 2000, the short cut method resulted in revenue requirements which were $235,677, or .096%, lower than revenue requirements under the full utility-type regulatory treatment methodology. Florida Power continues to believe that this analysis confirms the appropriateness of the short cut method.

Q. Has Florida Power properly calculated the market price true-up for coal purchases from Powell Mountain?

A. Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 860001-EI-G.

Q. Has Florida Power properly calculated the 2000 price for waterborne transportation services provided by Electric Fuels Corporation?

A. Yes. The 2000 waterborne transportation calculation has been reviewed by Staff and Public Counsel and deemed properly calculated.

Q. What is the appropriate regulatory treatment for capital projects with in-service date on or after January 1, 2002, that are expected to reduce long-term fuel costs?

A. The Commission should continue its long standing practice of allowing cost recovery for capital projects which produce customer fuel savings in excess of the cost to achieve, so long as the costs are not being recovered through base rates or elsewhere. This practice serves two purposes: First, it matches the project's costs with the same recovery mechanism that provides the project's benefits. Secondly, it encourages utilities to pursue these cost saving projects by eliminating the revenue requirement deficiency they would otherwise experience.

Q. What is the appropriate rate of return on the unamortized balance of capital projects with an in-service date on or after January 1, 2002, that are expected to reduce long-term fuel costs?

A. The appropriate rate of return is the utility's current cost of capital determined using the return on equity approved in its last base rate proceeding.

Q. If an investor-owned electric utility exceeds the ceiling on its authorized return on common equity, can and/or should the Commission reduce by a commensurate amount recovery of prudently incurred expenditures through the Commission's fuel and purchased power cost recovery clause?

A. The Commission cannot and should not use the fuel adjustment clause to remedy a utility's base rate over-earnings, any more than the Commission can or should use the clause to remedy a utility's under-earnings. The use of a pass-through clause as a true-up mechanism for base rates would be contrary to the statutory scheme governing the permissible actions the Commission may take to address a utility's over- or under-earnings.

Q. Should the Commission allow Florida Power to recover payments made to Lake Cogen, Ltd., resulting from litigation between Florida Power and Lake Cogen?

A. The Commission should allow recovery of the payments Florida Power is required to make to Lake Cogen by the court's final order. Since 1994, when Florida Power began making payments to Lake Cogen and other similarly situated cogenerators based on its interpretation of the contractual energy pricing provisions, the Company has diligently pursued the support of this energy pricing interpretation by the Commission and the defense of the interpretation in numerous lawsuits brought against Florida Power by the affected cogenerators.

At the time Florida Power implemented this energy pricing interpretation in 1994, the Company petitioned the Commission to determine that it had done so correctly. The Commission dismissed the Company's petition, stating "We defer to the courts to answer the question of contract interpretation raised in this case." Florida Power then focused on defending its energy pricing interpretation before the courts in litigation filed by various cogenerators. Over the next several years Florida Power reached settlements in the litigation with Lake Cogen and four other cogenerators, including one that was nearly identical in timing and substance to the Lake settlement. While the other settlements presented to the Commission were approved, the Commission denied, by a vote of three to two, Florida Power's petition for approval of the settlement with Lake Cogen. Because the Company viewed the Commission's reasoning in its Lake settlement order as a clear departure from the rationale for its dismissal of Florida Power's 1994 petition, Florida Power again petitioned the Commission for a determination that its interpretation of the energy pricing provision was correct. The Commission, however, denied this petition as well, again by a three to two vote, ruling that its decision on Florida Power's initial 1994 petition was controlling.

The litigation with Lake Cogen then proceeded to trial, which resulted in a ruling by the court generally favorable to Florida Power. However, as described earlier, the trial court's ruling was overturned on appeal. Florida Power asked the appellate court to reconsider its decision or, alternatively, to certify that the case involves a question of great public importance, which would have provided a basis for appeal to the Florida Supreme Court. Neither request was granted, effectively ending the opportunity for further appeal.

As the Commission is aware, Florida Power has a long and continuous track record with its efforts to mitigate the effects of its high cost cogeneration contracts through settlements, innovative modifications, contract restructuring, buy-outs, early terminations and the purchase of cogeneration facilities. The Company's Tiger Bay purchase and contract termination transaction, by itself, is expected to save the Company's customers over $2 billion. As another example of these mitigation efforts, Florida Power anticipates submitting to the Commission in the near future a proposal to restructure two more cogeneration contracts in a manner that will reduce the cost of these contracts to customers.

Clearly, the Lake Cogen piece of Florida Power's cogeneration mitigation program did not have the positive outcome that the Company and the Commission would have preferred. However, this outcome occurred despite Florida Power's efforts and commitment over the last seven years and, in fairness, should be viewed in the context of the significant customer benefits the Company's overall cogeneration mitigation program has achieved.

Q. Does this conclude your testimony?

A. Yes.

BY MR. McGEE:

Q As I had indicated earlier, Mr. Portuondo's -- all of the issues that are supported by Mr. Portuondo's testimony have been either stipulated or withdrawn. He is here to respond to the two more recent issues, which would be 17B and 17C relating to security cost and revised forecast. And I'd ask Mr. Portuondo to give us a brief summary of the company's position on those two issues.

A Good morning, Commissioners. I'm here to address items -- or Issues 17B and 17C. 17B deals with the recovery of incremental security costs as a result of the acts on September 11th, 2001. Florida Power's position is that it is in full agreement and supports the position of NARUC and FERC regarding the desirability of providing for recovery of these increased security costs resulting from the events of September 11th. We are not, at this point, sure of what the recovery method should be. We have not had the opportunity to review the possibilities that might be available for the recovery of those costs.

With regards to 17C, the company's position is that a revised forecast is not necessary at this time, that the Commission has policies and procedures in place that would allow immediate action among the part of the companies to implement a change to the factor should the situation dictate that it is appropriate and the full analysis of the impacts from the events of September 11th are fully analyzed and the ongoing conflict in the Middle East is fully evaluated.

Thank you.

MR. McGEE: Mr. Portuondo is available for cross-examination.

CHAIRMAN JACOBS: Mr. Vandiver.

MR. VANDIVER: No questions.

CHAIRMAN JACOBS: Questions.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Would you please look at your Exhibit E1.

A (Witness complies.)

Q Am I correct -- if you look at Line 5, am I correct that for you to generate power, the average projected cost for the year 2002 will be $26.52 for the power produced by your own generating capacity?

A Yes, sir.

Q And in addition to that power, you will purchase power from other sources, and the average cost of that purchased power is less than your cost of generation which is $22.65 a megawatt hour?

A Yes, sir.

Q And you're going to sell 109 -- or you're going to sell 2.8 million megawatt hours on the wholesale market, and for that you're going to collect $38.73 a megawatt hour?

A Yes, sir.

Q And that's substantially more than you pay to generate electricity of your own capacity?

A Yes, sir.

Q And you flow the entire cost of those sales less your incentive bonus, if any, to the retail customers?

A Yes, sir.

Q You have a true-up on Line 28 for the forthcoming year of $23 million that wasn't collected in 1961, but if I look at your Schedule E1B, it looks like your negative balance in July -- on July 1 was $61 million.

A Yes, sir.

Q Is that correct?

So between July and the end of the year, that $61 million number will be reduced to the $23 million based on current fuel factors?

A Yes, sir.

Q And your proposed fuel factor for the next year is $26.87 --

A Yes, sir.

Q -- which is at the bottom of -- Line 34, I guess, on Schedule E1?

A Yes, sir.

Q And how does that compare to last year's charge?

A Last year's charge was 2.880.

Q So you've reduced your fuel factor?

A Yes, sir.

Q And you're able to retire the remaining flow-through from the 2000 year -- the year 2000 without increasing your factor whatsoever?

A Yes, sir.

Q That was a poorly worded question, I apologize.

In your Exhibit E7, you show that during the year 2002 you're going to buy 347,000 megawatt hours from Tampa Electric.

A Yes, sir.

Q And Tampa Electric -- you're going to pay Tampa Electric $32 a megawatt hour for that power?

A Yes, sir.

Q Do you pay Tampa Electric any money in addition to the $32?

A There is a capacity charge as well.

Q A wheeling charge?

A Capacity.

Q Oh, capacity charge. What is the amount of the capacity charge?

A Approximately -- on an annual basis, approximately 6.8 million.

Q $6.8 million?

A Yes, sir.

Q And is this classified as a separated sale?
A No, sir.
Q I beg your pardon?
A No, sir.
Q It is not. It's an all requirements sale?
A This is a purchase.
Q Is it under --
A This is a purchase from Tampa, not a sale.
Q You don't know how Tampa Electric classifies it, do you, whether it's separated or nonseparated?
A No, I do not.
Q And when was the contract entered into?
A I don't recollect. It's been a number of years. I don't recollect the date.
Q Before or after 1997? Do you know that?
A I believe this was before '97.
Q And under that contract -- was it before 1992?
A I don't believe so. I think it was around the '92 time frame.
Q How much capacity are you entitled to under that contract?
A It's -- subject to check, I believe it's around 60 megawatts.
Q Sixty megawatts?
A Yeah.

Q Is that firm capacity?
A Yes, sir.
MR. McWHIRTER: No further questions.
CHAIRMAN JACOBS: Staff.

CROSS EXAMINATION

BY MR. KEATING:
Q Mr. Portuondo, has Florida Power updated its energy and demand forecasts as part of its -- in support of its MFR filing in Florida Power Corporation's rate proceeding?
A Yes, we have.
Q Was that updated to take into account the economic impacts of the September 11th events?
A Yes, it was.
Q But Florida Power's proposed cost recovery factors in this docket are based on a forecast that doesn't take into account those impacts; is that correct?
A That is correct.
Q Could you explain why Florida Power has provided an undated forecast to support its rate case filing but not to support its fuel and purchased power filing?
A The reason that we have not updated the fuel forecast filing is because the -- of the uncertainty with regards to fuel prices themselves. We have updated the sales forecast, but we are monitoring the situation and what impacts the current actions may have on future commodity prices. And given

the number of variables that could be affected in the fuel forecast, we did not believe it was prudent at this time to change the factor just to possibly have to change it again if commodity prices would start to become volatile.

Q Would the -- in your opinion, would the updated forecasts of energy and demand that were provided as part of the rate proceeding materially affect either Florida Power's 2002 fuel or capacity cost recovery factors?

A The sales alone would not materially affect the factor.

Q I just have a couple questions related to the security costs that Florida Power may incur as a result of those terrorist acts on September 11th. What, in your opinion, is the most appropriate recovery mechanism for incremental security costs as a result of the September 11th events?

A I have not had an opportunity to determine what is the most appropriate mechanism at this time.

Q Do you believe that the fuel clause is the most appropriate recovery mechanism or an appropriate recovery mechanism?

A Not having had time to evaluate other options, I just cannot, you know, speak to that at the moment.

Q Is it correct that Florida Power Corporation has included an estimated amount of those costs in its MFR filing to be recovered through base rates?

A The costs that have been included in its recent MFR filings are those capital costs which will be a permanent investment. We have not included the incremental O&M costs.

MR. KEATING: Thank you. That's all the questions I have.

CHAIRMAN JACOBS: Commissioners.

Mr. Portuondo, as I understand it, much of the adjustment factors are tied to changes in the fuel market that occurred over the last year. It would occur (sic) that in view of recent trends that most of those in the next cycle are going to be pretty much reversed. Is that a fair statement, in your mind?

THE WITNESS: We are monitoring the price fluctuations and that we have seen some of the declines in the prices.

CHAIRMAN JACOBS: Going to the security issue. Most companies have in place plans -- emergency preparation plans that are long-standing; is that correct? In other words, you've had facilities personnel and practices that have been in place for sometime as it deals with disasters; is that correct?

THE WITNESS: Due to natural disasters, hurricane recovery plans, and things of that nature, yes, sir.

CHAIRMAN JACOBS: So the incremental expenses here wouldn't have to do with unforeseen -- something --

THE WITNESS: Yeah, a situation like we are presented with today.

CHAIRMAN JACOBS: And I assume that there's some kind of risk versus -- there is some level of risk aversion, some quotient of risk aversion that is being developed within a corporation. In other words, you know, we've heard all the time that you could try and protect for any unknown circumstance, but perhaps the risk of that circumstance happening may be very small so that expense of preparing to deal with that risk perhaps is reasonable or unreasonable. Is that -- so my question is, is there some evaluation being undertaken in your company to determine what those bounds of reasonableness are?

THE WITNESS: Mr. Chairman, I'm not directly involved in that discussion, but I would expect that the company is working very closely with all the federal agencies to make sure that all the security necessary to address whatever threats may be conceived are being dealt with appropriately.

CHAIRMAN JACOBS: Very well. There's been much discussion of FERC's and NARUC's position. In just a matter of just two minutes ago, I was on the phone with the president of NARUC discussing this very matter, and there is a lot of discussion about what exactly that discussion should be. So it anticipates further details on that. Thank you.

Redirect.

MR. McGEE: No redirect. We would ask the admission of composite exhibit --

CHAIRMAN JACOBS: Show Exhibit 12 is admitted without objection.

(Exhibit 12 admitted into the record.)

CHAIRMAN JACOBS: Thank you, Mr. Portuondo.

(Witness excused.)

MR. KEATING: And, Mr. Chairman, before we move on to the next witness, this may be an appropriate time for staff to have an exhibit marked. This is an exhibit we had -- a composite exhibit --

CHAIRMAN JACOBS: This is for which witness?

MR. KEATING: It's for various witnesses. It's material that was gathered through discovery that we believe supports the stipulated issues.

CHAIRMAN JACOBS: While we're doing that, Mr. Badders, why don't we go ahead and take care of your witness?

MR. BADDERS: Thank you, Mr. Chairman. It's my understanding that there are no questions for Witness Terry Davis. All of the issues that she's listed on are stipulated issues. So we'd go ahead and ask that all of her testimony be moved into the record along with the exhibits.

CHAIRMAN JACOBS: Very well. Without objection, show the testimonies of Ms. Davis are entered into the record as though read.

And let's identify her exhibits. Okay. So we will identify it as Composite Exhibit 13 -- and as I understand it, it would be TAD-1, 2 and 3?

MR. BADDERS: That is correct.

CHAIRMAN JACOBS: All right. Show those marked as Composite Exhibit 13. And without objection, show Exhibit 13 is admitted.

(Exhibit 13 marked for identification and admitted into the record.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 010001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: April 2, 2001

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

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

A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of four schedules be marked as Exhibit No. _____ (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the period of January 2000 through December 2000 and the Purchased Power Capacity Cost true-up calculations for the period of January 2000 through December 2000 set forth in your exhibit?

A. Yes. These documents were prepared under my direction.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period January 2002 through December 2002?

A. A net amount to be refunded of $6,907,921 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $6,907,921 was calculated by taking the difference in the estimated January 2000 through December 2000 under-recovery of $8,668,391 and the actual under-recovery of $1,760,470, which is the sum of the Period-to-Date amounts on lines 7 and 8 shown on Schedule A-2, page 2, of the monthly filing for December 2000. The estimated true-up amount for this period was approved in Order No. PSC-00-2385-FOF-EI dated December 12, 2000. Additional details supporting the approved estimated true-up amount are included on Schedule E1-A filed August 21, 2000.

Q. Ms. Davis has the estimated benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for 2001?
A. Yes, it has.

Q. What is the actual threshold for 2001?
A. Based on actual data for 1998, 1999, and now 2000, the threshold is calculated to be $886,926.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?
A. Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation for the period January 2000 through December 2000.

Q. What is the amount to be refunded or collected in the period January 2002 through December 2002?
A. An amount to be refunded of $340,856 was calculated as shown in Schedule CCA-1, of my exhibit.

Q. How was this amount calculated?
A. The $340,856 was calculated by taking the difference in the estimated January 2000 through December 2000 under-

recovery of $331,059 and the actual over-recovery of $9,797, which is the sum of lines 12 and 13 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in Order No. PSC-00-2385-FOF-EI dated December 12, 2000. Additional details supporting the approved estimated true-up amount are included on Schedule CCE-1A filed August 21, 2000.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2000 through December 2000. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2000 through December 2000. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 010001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: Revised September 25, 2001

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of five schedules be marked as Exhibit No. _____ (TAD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2001 through December 2001 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2001 through December 2001 set forth in your exhibit?

A. Yes. These documents were prepared under my direction.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case for the estimated true-up calculations includes seven months of actual data and five months of estimated data.

Q. Ms. Davis, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2002 through December 2002?

A. The fuel cost recovery true-up for this period is an increase of .1042¢/kwh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2001 period of $17,609,612, plus a final over-recovery for January through December 2000 period of $6,907,921 (see Schedule 1 filed April 2, 2001). The resulting under-recovery is $10,701,691.

Q. Are there any significant adjustments to the fuel cost recovery clause reflected in the schedules to your exhibit?
A. Yes. In accordance with Order No. PSC-99-2131-S-EI concerning Gulf's revenue sharing plan, a one-time adjustment of $221,982 was made in the fuel clause in May 2001. The adjustment is shown on Schedule E-1B. It represents the difference between the amount calculated to be refunded and the actual refunds made.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?
A. Schedules CCE-1a and CCE-1b of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2002 through December 2002 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2002 through December 2002?
A. The true-up for this period is a decrease of .0181¢ as shown on Schedule CCE-1a. This includes an estimated over-recovery of $1,515,391 for January 2001 through

December 2001. It also includes a final true-up over-recovery of $340,856 for the period of January 2000 through December 2000 (see Schedule CCA-1 filed April 2, 2001). The resulting over-recovery is $1,856,247.

Q. Ms. Davis, does this complete your testimony?
A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 010001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: September 20, 2001

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in Docket No. 010001-EI?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2002 through December 2002. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2002 through December 2002.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2002 through December 2002?
A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have.

Counsel: We ask that Ms. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. ______(TAD-3).

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2000 through December 2000?
A. The GPIF result is shown on Line 32 of Schedule E-1 as an increase of .0037¢/kwh, thereby rewarding Gulf with $379,732.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?
A. A revenue tax factor of 1.01597 has been applied to all jurisdictional fuel costs as shown on Line 30 of Schedule E-1.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2002 through December 2002?
A. Gulf has proposed a levelized fuel factor of 2.212¢/kwh. It includes projected fuel and purchased power energy expenses for January 2002 through December 2002 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?
A. The projected levelized fuel factor for 2002 is .392 cents/kwh more or 21.5 percent higher than the levelized fuel factor for 2001 upon which current fuel factors are based.

Q. Ms. Davis, how were the line loss multipliers used on Schedule E-1E calculated?
A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Davis, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 2.239¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Ms. Davis, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period January 2002 through December 2002. These factors included the GPIF and true-up, and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2001 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2001 is 1.842¢/kwh compared with the proposed factor of 2.239¢/kwh. For a residential customer who uses 1000 kwh in January 2002, the fuel portion of the bill would increase from $18.42 to $22.39.

Q. Ms. Davis, has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit TAD-3. These costs represent the estimated averages for the period from January 2002 through December 2003.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2002 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Staff's implementation plan, a benchmark level of $1,208,241 has been calculated for 2002. The actual gains for 1999, 2000, and the estimated gains for 2001 on all non-separated sales have been averaged to determine the minimum projected threshold for 2002 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2002. The estimated gains on all non-separated sales are projected to be $449,000, whereas the threshold is estimated at $1,208,241.

Q. What is the appropriate regulatory treatment for capital projects in the fuel cost recovery clause?

A. When an electric utility incurs prudent capital costs eligible for fuel cost recovery, the company should be allowed to recover the carrying costs associated with that project. The recoverable carrying costs should include the return on investment, depreciation expense, and the dismantlement accrual. This is consistent with practices allowed by this Commission in this and other cost recovery clauses.

Q. What capital structure and return on equity should be used to develop the rate of return for calculating the revenue requirement for capital projects?

A. The rate of return used should be based on the company's capital structure that was approved in the company's last rate case. This is consistent with the methodology approved by this Commission for calculating revenue requirements in the Environmental Cost Recovery Clause in Order No. PSC-94-0044-FOF-EI dated January 12, 1994 in Docket No. 930613-EI.

Q. Ms. Davis, you stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2002 through December 2002.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC), Gulf's contract with Solutia, and certain market capacity transactions. Gulf's total projected net capacity expense for the period January 2002 through December 2002 is $3,584,605. The jurisdictional amount is $3,459,412. For the projection period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an annual embedded credit of $1,678,580, or $1,652,000 net of revenue taxes. Thus, the projected recovery amount that would be collected through the PPCC recovery factors in the period January 2002 through December 2002 is $5,111,412. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. 23573 issued October 3, 1990, in Docket No. 891345-EI. Although the capacity payments in that cost of service study were allocated to rate class using the demand allocator based on the twelve monthly coincident peaks projected for the test year, for purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 1999 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, the 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $.38.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2002 and continuing through the last Bill Group for December 2002.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

MR. BADDERS: There are also several Gulf Power witnesses, but I believe all those witnesses were moved in at the beginning of this proceeding. But there are exhibits to those that would need numbers.

MR. KEATING: I do not believe that --

CHAIRMAN JACOBS: Yeah, I do not believe we did.

MR. KEATING: -- the testimony of any of the excused witnesses had been moved in yet.

CHAIRMAN JACOBS: Not in this docket.

MR. BADDERS: Okay. So we'll go ahead and move those in --

CHAIRMAN JACOBS: Yes.

MR. BADDERS: -- one by one. First, we'll move Witness Oaks.

CHAIRMAN JACOBS: Without objection, show the testimony of Mr. Oaks is admitted into the record as though read.

MR. BADDERS: We'd also like to identify and move into the record his two exhibits which are MFO-1 and MFO-2.

CHAIRMAN JACOBS: Show those marked as Composite Exhibit 14.

(Exhibit 14 marked for identification.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Michael F. Oaks
Docket No. 010001-EI
Date of Filing: April 2, 2001

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0328.

Q. What is your occupation?
A. I am the Fuel Manager at Gulf Power Company.

Q. Mr. Oaks, will you please describe your education and experience?
A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Manager?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided a high quality fuel supply at the lowest practical cost.

Q. Mr. Oaks, have you previously testified before this Commission?

A. Yes. I have presented testimony to this Commission previously in this docket.

Q. Mr. Oaks, what is the purpose of your testimony in this docket?

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses and to certify that these expenses were properly incurred during the period January 2000 through December 2000. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

A. Yes. I have prepared an exhibit consisting of one schedule.

Counsel: We ask that Mr. Oaks' exhibit consisting of one schedule be marked as Exhibit No. ______________ (MFO-1).

Q. During the period January 2000 through December 2000 how did Gulf's recoverable fuel expenses compare with the projected expenses?

A. Gulf's recoverable fuel expense was $211,767,566 or 7.53% over the projected amount of $196,934,163. Total net system generation for the period was also higher than projected. Actual generation was 12,865,732 MWH compared to the projected generation of 12,271,910 MWH or 4.84% more than predicted. The resulting total fuel cost per KWH generated was 1.6460¢/KWH or 2.57% over the projected amount of 1.6048¢/KWH. The increase in actual expenses over projected was primarily a result of a slightly higher coal burn of 3.74% more MMBtu's for the period, along with significantly higher usage of natural gas and oil fired generation coupled with much higher prices for these fuels than projected.

Q. How much spot coal did Gulf Power Company purchase during the period?

A. Excluding Plant Scherer 3, Gulf purchased 2,645,898 tons or 56% of supply from the spot coal market. My Schedule 1 of Exhibit No. (MFO-1) consists of a list of contract and spot coal suppliers for the period January 1, 2000 - December 31, 2000.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased was $189,491,967 compared to our projection of $199,047,184, or 4.8% lower than projected.

Q. How did the total projected cost of coal burned compare with the actual cost?

A. The total actual cost of coal burned was $200,914,118 compared to our projection of $191,963,769, or 4.66% higher than projected. However, on a fuel cost per MMBtu basis, the actual cost (including startup fuel) was $1.55/MMBtu, less than 1% higher than the projected $1.54/MMBtu.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. Yes, as discussed in previous testimony and ordered by the FPSC, it was determined that burning bituminous coal at Plant Daniel was the most cost effective method to increase Gulf Power Company's capacity resources by 52 MW.

Because of the operational problems and loss of capacity associated with continuing to burn Decker Powder River Basin coal (Decker), 700,000 tons (Gulf Power's portion - 350,000 tons) were deferred under the terms of the contract from 1999 to 2000. After significant additional operational problems were encountered during early 2000 while attempting to burn the Decker during off peak months, it became necessary to buyout of the remaining obligation of 311,500 tons (Gulf Power's portion).

Based on market conditions at the time, it was originally projected that the buyout would result in a net reduction in fuel cost of about $27,000. However, because the sulfur content of the Decker coal and the replacement fuels were both lower than the original projection, the transaction actually resulted in a total net increase in fuel cost. An estimate using the average delivered 1999 Decker sulfur level and actual 2000 sulfur levels of the replacement fuels results in a net increase in fuel cost to Gulf Power's customers of about $32,000, considering the total cost including SO_2 allowances.

The cost of the buyout is insignificant when compared to the value of the additional 52 MW of coal fired capacity that was made available to customers. Even though the Decker coal would not have been burned during the summer peak season of 2000, the savings realized by replacing it during the off peak more than compensated for the cost of the buyout. For example, the value to Gulf's customers of having this capacity available for just one day during December 2000 (December 19, 2000) was $119,565. Although the replacement was accomplished in the winter, spring, and fall of 2000, because the buyout tons were deferred from 1999, the additional 52 MW of coal fired capacity was also made available to Gulf's customers during the peak season of 1999.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply plan is based on a combination of long term contracts and spot purchases at market prices. Coal vendors are selected by procedures designed to assure a reliable quantity of high quality coal at competitive delivered prices. Gulf has administered the provisions of its contracts and purchase orders appropriately. Natural gas was purchased using short-term forward contracts and from the spot market on an as-needed basis. Gas was also purchased and placed into storage to ensure a reliable supply. All of Gulf's oil purchases were from oil vendors selected by open bids to ensure the most economical price of oil.

Q. Mr. Oaks, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Michael F. Oaks
Docket No. 010001-EI
Date of Filing: August 20, 2001

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520-0335.

Q. What is your occupation?
A. I am the Fuel Manager at Gulf Power Company.

Q. Mr. Oaks, will you please describe your education and experience?
A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Manager?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided a high quality fuel supply at the lowest practical cost.

Q. Mr. Oaks, have you previously testified before this Commission?
A. Yes. I have presented testimony to this Commission previously in this docket.

Q. Mr. Oaks, what is the purpose of your testimony in this docket?
A. The purpose of my testimony is to compare projected fuel expenses with estimated/actual costs for the January through December 2001 recovery period and to summarize any noteworthy developments in Gulf Power Company's fuel program. Also, it is my intent to be available to answer questions that may arise in this docket concerning Gulf Power Company's fuel expenses.

Q. During the period January 2001 through December 2001, how will Gulf's estimated/actual recoverable fuel expenses compare with the original projection of expenses?
A. Gulf's expected recoverable fuel expense for the period is now $206,421,953 or 3.24% more than the original projected amount of $199,947,293. Total net system generation for the period is expected to be 12,535,311 MWH compared to a projection of 12,669,590 MWH or 1.06% less than originally forecast. The resulting total fuel cost per KWH generated will be 1.6467¢/KWH or 4.34% higher than the projected cost of 1.5782¢/KWH. The increase can be primarily attributed to an extremely tight fuel market and resulting higher prices paid for spot coal tons.

Q. How did the total projected cost of coal compare with the actual cost during the first seven months of 2001?

A. The total actual cost of coal burned was $117,444,972 compared to a projected cost of $108,511,616, or 8.23% higher than projected. Also, considerably more coal was purchased during the period than projected resulting in the total cost of coal purchased being significantly higher. Actual purchases were $140,549,928 as compared to projected purchases of $103,603,877. The increase was necessary because of much lower than desired inventory levels going into 2001. Extreme winter weather conditions and high gas prices created very strong demand for coal fired generation during the fourth quarter of 2000 and early 2001. The higher demand coupled with a slowdown in coal deliveries during the second half of 2000 caused the low inventory situation. It is imperative that Gulf build coal inventories during the first half of the year to be prepared for the summer peak and hurricane season.

Q. How did the total projected cost of natural gas compare with the actual cost during the first seven months of 2001?

A. Gulf purchased 224,398 MCF during the period, about 31% less than the projected amount of 324,194 MCF. Gas prices have remained relatively high throughout the period, and demand for Gulf's gas-fired peaking capacity has been lower than projected. For the period, the total actual cost of gas burned was $1,220,453 compared to a projected cost of $1,694,194.

Q. Are there other significant developments in Gulf's fuel procurement program for 2001 recovery period?

A. Yes, force majeure conditions at three major suppliers' mines resulted in increased purchases of spot coal in an already tight market. These replacement spot tons are at a higher price than what Gulf modeled in its original projection.

Q. Should Gulf's fuel purchases for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal purchases were either from long term contracts or the competitive spot market. Coal vendors are selected by procedures designed to assure a deliverable quantity of high quality coal for a specific term at the lowest available delivered cost. Gulf has administered the provisions of its contracts and purchase orders appropriately. Natural gas was purchased utilizing forward physical contracts and from the spot market on an as-needed basis or purchased and placed into storage to ensure a reliable supply. All of Gulf's oil purchases were from oil vendors selected by open bids to ensure the most economical price of oil.

Q. Mr. Oaks, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Michael F. Oaks
Docket No. 010001-EI
Date of Filing: September 20, 2001

Q. Please state your name and business address.
A. My name is Michael F. Oaks and my business address is One Energy Place, Pensacola, Florida 32520.

Q. What is your occupation?
A. I am the Fuel Manager at Gulf Power Company.

Q. Mr. Oaks, will you please describe your education and experience?
A. I graduated from Belhaven College in Jackson, Mississippi, in 1977 with a Bachelor of Science Degree in Chemistry. I joined Gulf Power Company in 1977 as a Chemist. Since then, I have held various positions with the Company, including Water Chemistry Specialist, Water Quality Specialist, Environmental Affairs Specialist, Environmental Audit Administrator, and Compliance Administrator. I was promoted to my present position in May 1996.

Q. What are your duties as Fuel Manager?
A. I supervise and administer the Company's fuel procurement, transportation, budgeting, contract administration, and quality control to ensure the generating plants are provided an adequate low cost fuel supply with minimal operational problems.

Q. Are you the same Michael F. Oaks who has previously submitted testimony in this proceeding.

A. Yes.

Q. Mr. Oaks, what is the purpose of your testimony in this docket?

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses for the period January 1, 2002 through December 31, 2002, to address Issue 11 raised in Order No. PSC-01-1829-PCO-EI of this docket, and to be available to answer any questions that may arise concerning the Company's fuel procurement procedures.

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

A. Yes. I have prepared an exhibit consisting of one schedule. Schedule 1 of my exhibit is a tabulation of projected and actual fuel cost for the past ten years. The purpose of this schedule is to illustrate the accuracy of our short-term projections of fuel expenses.

Counsel: We ask that Mr. Oaks' exhibit consisting of one schedule be marked as Exhibit No. _______________ (MFO-2).

Q. Has Gulf Power Company made any changes to its methods in this period for projecting fuel cost?

A. No.

Q. Does the 2002 projection of fuel expenses reflect any major changes in Gulf's fuel purchasing program during this period?
A. Yes, the projection for this period includes seven months of natural gas expenses associated with Smith Unit 3 which is scheduled to begin commercial operation on June 1, 2002.

Q. How much spot market coal does Gulf Power project it will purchase during the January 2002 through December 2002 period.
A. We are projecting the purchase of approximately 1,868,775 tons on the spot market. This represents approximately 33.57% of our projected purchase requirements.

Q. Has Gulf Power taken reasonable steps to manage the risks associated with its fuel transactions through the use of physical and financial hedging practices?
A. The strategy employed by Gulf Power for managing these risks has been very reasonable, and effective, as evidenced by our reliability and low rates. The Company has not engaged in financial hedges, but on the physical side, has engaged in certain fixed price fuel supply agreements to meet the requirements of its plants. Gulf Power endeavors to put together a balanced fuel supply portfolio consisting of a mix of spot and long-term contracts at both market and fixed prices. The objective is to produce a cost effective yet highly reliable fuel supply.

Q. Mr. Oaks, does this conclude your testimony?

A. Yes.

(Transcript continues in sequence in Volume 4.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, TRICIA DeMARTE, 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 3RD DAY OF DECEMBER, 2001.

Tricia DeMarte

TRICIA DeMARTE
FPSC Official Commission Reporter
(850) 413-6736