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
_______________________________/

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VOLUME 1

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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:	Tuesday, November 20, 2001
TIME:	Commenced at 9:30 a.m. Concluded at 5:25 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Chief, Office of Hearing Reporter Services FPSC Division of Commission Clerk and Administrative Services (850) 413-6732

APPEARANCES:

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LEE L. WILLIS and JAMES D. BEASLEY, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company (TECO).

JOHN W. MCWHIRTER, JR, and VICKI GORDON KAUFMAN, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, P.A, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group (FPIG).

MATTHEW M. CHILDS, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company (FPL).

APPEARANCES CONTINUED:

ROBERT D. VANDIVER, Associate Public Counsel, Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

TOM CLOUD, Gray, Harris and Robinson, P. A., 201 South Bronough Street, Suite 600, Tallahassee, Florida 32301, appearing on behalf of Publix Super Markets, Inc.

WILLIAM COCHRAN KEATING, IV, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
1	JDJ-1	34	144
2	JDJ-2	35	144
3	JDJ-3	36	144
4	Composite of Deposition Transcripts and Various Documents	118	129
5	(Confidential) Responses to Interrogatories 5, 6, 149 and 150	118	129

CERTIFICATE OF REPORTER

PROCEEDINGS

CHAIRMAN JACOBS: Very well. We will go back on the record. And we are prepared to consider Docket 01. I do not believe there were any pending preliminary matters on this.

Is that correct, Staff?

MR. KEATING: There are a couple of motions listed in the prehearing order as pending motions. Those do not require ruling at this time. One concerns a motion for reconsideration of an order on a motion for protective order. Any information that is the subject of that motion the parties have been asked to treat as confidential for purposes of this hearing. I believe that information includes supplier names of Tampa Electric wholesale purchases, so that has been -- the parties have been asked to treat that as confidential pending a ruling on that in due time.

CHAIRMAN JACOBS: Very well. I'm sorry.

MR. KEATING: Pending a ruling on that in due time. The second motion is a motion for protective order that is related to materials that would not be used at this hearing, so there is no ruling necessary at this time.

CHAIRMAN JACOBS: Okay. If everybody is in agreement to that.

MR. BEASLEY: Mr. Chairman, I had a couple of minor preliminary matters. If you wanted to take them up now, I would be happy to raise them.

CHAIRMAN JACOBS: Let's hear them.

MR. BEASLEY: Mark Hornick's testimony, last week we contacted counsel for the parties, we were told that no one had cross-examination questions, and so I would ask that Mr. Hornick's testimony be inserted and that he be excused.

CHAIRMAN JACOBS: If there is no opposition then we can insert Mr. Hornick's testimony into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 09/20/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK J. HORNICK

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

A. My name is Mark J. Hornick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of General Manager - Polk and Phillips Power Stations.

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

A. I received a Bachelor of Science Degree in Mechanical Engineering in 1981 from the University of South Florida. I began my career with Tampa Electric in 1981 as an Engineer Associate in the Production Department. I have held a number of engineering and management positions at Tampa Electric's power generating stations. In July 1998, I was promoted to Director - Fuels where I was responsible for managing Tampa Electric's fuel-related activities. In March 2000, I transferred to my current role of General Manager - Polk and Phillips Power Stations. I am responsible for the overall operation of these two generating facilities.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to provide an overview of Tampa Electric's generating facilities, a general description of the company's operation and maintenance practices and procedures and to address operating events that have impacted the fuel, purchased power and capacity costs in recent years.

Q. Please briefly describe the generating facilities Tampa Electric has in place.

A. Tampa Electric has six generating plants consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, and Polk.

Tampa Electric currently has 11 coal-fired units. Ten of these units are fired with pulverized coal. Starting in 2003, Tampa Electric will increase the diversity of its generation mix with the repowering of Gannon Station. The station will be repowered with natural gas and renamed Bayside Power Station.

Generating units at Hookers Point and Phillips are residual oil fired. Dinner Lake is fueled by natural gas and oil and is currently on long term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 2000 was 17,283 GWh.

Q. Please provide an overview of the practices and procedures Tampa Electric utilizes in maintaining and operating its generating units?

A. Tampa Electric uses a variety of both "industry standard" and "state of the art" practices to ensure that its generating units are properly maintained and operated. Standard industry practices for generating unit maintenance include job planning and scheduling, work task analysis, preventative maintenance and critical spare part inventory management. Tampa Electric has also implemented numerous advanced maintenance practices. These include vibration analysis, lube oil analysis, thermography, reliability-centered maintenance, root cause failure analysis, computerized maintenance management, employee continuous improvement programs and craftsman multi-skilling.

To ensure the proper operation of its generating units, Tampa Electric utilizes systems and practices including operator training, task analysis, competency testing, operating procedures and checklists, unusual incident reporting and analysis, engineering and technical evaluation of equipment performance and routine testing of critical safety devices. In addition, Tampa Electric uses numerous automated systems to ensure proper unit operation. These include analog and digital control systems, alarm condition annuciators, comprehensive monitoring and diagnostic systems and automatic safety shutdown systems. These comprehensive programs and practices have allowed Tampa Electric to achieve reasonable levels of unit performance with well managed costs, while utilizing some older generating equipment portfolio and coping with significant environmental requirements.

Q. What operating conditions have impacted Tampa Electric's fuel and purchased power costs in recent years?

A. In recent years, Tampa Electric has experienced increased needs for purchased power due to several key operational events which include the Gannon Station accident in 1999, the failure of the Gannon Unit 6 generator in 2000, extended outages due to environmental constraints at Big Bend Station and other operating issues.

Q. Please provide a brief summary of the occurrences at Gannon Station in 1999 and 2000?

A. On April 8, 1999, Gannon Unit 6 was in the early phase of a planned maintenance outage. During the initial phase of work a generator access cover was removed while hydrogen was still inside the generator casing under pressure. The escaping hydrogen ignited, causing a flash fire and structural damage.

The explosion damaged Units 5 and 6 and caused an emergency shutdown of all five Gannon Station units that were operating. While Gannon Units 1, 2, 3 and 4 returned to service within a few days of the explosion, Gannon Units 5 and 6 were out of service until May 16, 1999 and June 22, 1999, respectively. The recoverable incremental fuel and purchased power costs that resulted from the explosion totaled $5.1 million, as discussed by

Tampa Electric's witness Mark D. Ward in his direct testimony filed October 1, 1999 in Docket No. 990001-EI.

An unrelated and extended unplanned outage at Gannon Unit 6 began on July 18, 2000. The cause of the outage was an in-service failure of the generator stator winding. Upon disassembly, the stator windings were severely damaged by a high current fault. The generator required a complete stator and field rewind. Tampa Electric was able to complete this extensive repair work and return the unit to service on December 12, 2000. Replacement power was purchased during this period, and the company estimated a net impact to fuel and purchased power costs of $20.3 million as a result of the outage, as discussed in the company's witness W. Lynn Brown's direct testimony filed on September 21, 2000 in Docket No. 000001-EI.

Q. Please provide a brief summary of the outages at Big Bend Station?

A. In addition to the typical planned and forced outages at Big Bend Station, the company has also faced additional environmental requirements. In 2000 Tampa Electric entered into a Consent Decree with the U.S. Environmental Protection Agency and Department of Justice. A key requirement involved the optimization and utilization of Big Bend Station's sulfur dioxide removal systems. The scrubbers for Big Bend Unit 1, 2 and 3 were originally designed to meet Clean Air Act requirements that allowed the scrubbers to be shut down for periodic maintenance while the generating units continued to operate. The Consent Decree essentially requires that the scrubbers be in service whenever the generating unit is operating.

To meet these more stringent operating requirements, Tampa Electric performed extensive scrubber maintenance during planned outages, and, in some instances, extended planned outages to ensure that the reliability of the generating units would not be jeopardized by scrubber problems. This included an outage in 2001 at Big Bend Station that was extended for 16 days. The company also performed maintenance work on the oxidation air header in the Big Bend scrubber towers to help ensure availability during peak periods. During these outage periods, the company purchased power to meet its retail load requirements.

Q. What other issues have impacted Tampa Electric generation operations in recent years?

A. Environmental regulations have also reduced the allowable nitrogen oxide emissions from the company's generating units. Tampa Electric has been able to comply with these rules with a series of innovative, cost effective modifications to the boilers and fuel burning equipment. While these modifications impact unit operation much less than other alternatives, the company still has experienced some capacity derations from changes in the combustion process.

In 2001, operations at Gannon Station have been impacted by an infestation of non-indigenous green lip mussels in Tampa Bay. These fast growing shellfish obstruct the tubes in the steam condensing equipment resulting in the units being restricted in capacity as sections of the condensers are taken out of service for cleaning. Tampa Electric is working with Mote Marine Laboratory and local officials to understand the extent of this problem and how to control the infestation.

Q. What significant operational items will affect Tampa Electric's fuel, purchased power and capacity costs for 2002?

A. Tampa Electric will continue to experience some capacity derations and availability losses due to the impacts of stricter environmental regulations. The company is working hard to minimize these impacts and to also find solutions to the mussel infestation problem.

The repowering of Gannon Station is clearly a significant undertaking. Construction work on Bayside is now in progress and we will perform a portion of the required conversion work during scheduled outage periods in 2002. However, this will impact the duration, timing and extent of the outages.

These factors have influenced the decision to negotiate several new firm capacity and energy purchases to meet desired operating reserves, as described in the direct testimony of Tampa Electric's witness W. Lynn Brown.

In addition, the company expects to bring Polk Unit 3, a 180 MW combustion turbine, which will use natural gas, in-service by May 2002. The addition of this unit will impact fuel costs in 2002.

Q. Does this conclude your testimony?

A. Yes.

MR. BEASLEY: And the only other matter that I had preliminarily is last week we filed a notice that we would intend to request official recognition of certain of the Commission's prior orders. And I have certified copies of those for the court reporter and additional copies for the Commissioners, staff, and parties. I would be happy to hand those out if you would like to receive them at this time.

CHAIRMAN JACOBS: Yes. This is for official recognition?

MR. BEASLEY: Yes, sir. I can give you a brief description of what these are if you would like.

CHAIRMAN JACOBS: Okay.

MR. BEASLEY: The first one is Commission's Order Number 22335 that was entered in Docket Number 880309-EC. That was the Commission's final order on need determination for the Hardee Power Station. And it was in that need order that you found that the various contracts that made up that project, including the Tampa Electric sale of Big Bend 4 capacity and energy to TPS would produce approximately $57 million in benefits to Seminole Electric Cooperative's customers and $90 million in benefits to Tampa Electric's retail customers.

The second item is simply excerpts of the company's last rate case where the Commission acknowledged the benefits derived from the Hardee Power Project, including the Tampa Electric Big Bend 4 sale to TPS.

The third one is your Commission order dated March 11, 1997, which is this Commission's definitive order setting forth the Commission's present policy for the regulatory treatment of separated and nonseparated wholesale sales.

The next one is your order of June 11, 2000, issued in the fuel docket, which is the order disposing of a motion for a midcourse correction filed by FIPUG. And that order in part reaffirms the Commission's regulatory policies that were in the March 11, 1997 order.

The final one is simply the consummating order for the last order I described. And we would offer these for your official notice. And I thank you for your time.

CHAIRMAN JACOBS: Thank you. Mr. McWhirter.

MR. McWHIRTER: Mr. Chairman, on behalf of FIPUG, I have no objection to the Commission taking official recognition of this order or any other of its orders. However, with respect to the 1993 rate order, I didn't get the extract until this morning. The order is 150 pages long, and just certain components have been selected and they may not be all of the relevant components. So I would suggest as an alternative that the entire order -- you take official recognition of the entire order and that we have that available, as well.

CHAIRMAN JACOBS: I'm sorry, please give me the order number again.

MR. McWHIRTER: This is Order Number 93-0165-FOF-EI, the 1993 rate order.

CHAIRMAN JACOBS: Let the record reflect we will take official recognition of that entire order.

MR. BEASLEY: Mr. Chairman, we have one further item. If you want to take it now, it's just a correction to a number in the prehearing order.

CHAIRMAN JACOBS: We can do that. What page?

MR. BEASLEY: It is Page 54, sir, and it is the -- the issue is stipulated Issue 28. And the number there for Tampa Electric, which is shown as $47,002,518 should be $52,600,466. I think the staff is in agreement with that. The factor shown in Issue 30 is based on that corrected number.

MS. KAUFMAN: I'm sorry, Mr. Beasley, would you mind repeating that again and referring us to the page.

MR. BEASLEY: Yes. It's on Page 54.

MS. KAUFMAN: Of the prehearing order?

MR. BEASLEY: That is correct. It may depend on which version you're looking at. I've got an earlier version and it was on Page 65.

MS. KAUFMAN: I've got the version that was issued with the order number on it.

MR. BEASLEY: It is stipulated Issue 28, Ms. Kaufman.

MS. KAUFMAN: Okay. I'm with you. It's on a different page.

MR. BEASLEY: Okay.

MS. KAUFMAN: Can you repeat your number again.

MR. BEASLEY: Yes. Instead of the 47 million plus, it is $52,600,466.

MR. McWHIRTER: We have no objection to that.

MR. BEASLEY: Thank you.

MS. KAUFMAN: Thank you, Mr. Beasley.

MR. KEATING: And staff is in agreement with that number, and that should be the stipulated position for that issue for TECO.

CHAIRMAN JACOBS: And you said Order 30 is already consistent with that number, is that correct? Issue 30.

MR. BEASLEY: That is correct.

CHAIRMAN JACOBS: Okay. Very well. Anything else from any of the parties?

MR. McWHIRTER: I would like to make a brief opening statement, Mr. Chairman, at the appropriate time.

CHAIRMAN JACOBS: Very well.

MR. BEASLEY: I would, as well, sir.

CHAIRMAN JACOBS: Did we reach a time limit on that?

MR. CLOUD: I believe the prehearing order says ten minutes.

CHAIRMAN JACOBS: Ten minutes.

MR. CLOUD: And I would like to make one, as well, for Publix.

CHAIRMAN JACOBS: Very well. And I assume we will go ahead and do it for each party. I was just thinking of whether or not we could break that out per side, but we can just go for each party. And would it be appropriate since it is your petition --

MR. BEASLEY: Okay, sir.

CHAIRMAN JACOBS: Mr. Childs, did you want to make an opening statement?

MR. BEASLEY: Yes, sir. Commissioners, Tampa Electric is ready to proceed. I believe the testimony and exhibits that we have filed demonstrate the merits of our position on the issues. It has all been thoroughly looked at by your staff. We are ready to go forward. I would like to reserve the balance of my time for rebuttal comments as necessary.

CHAIRMAN JACOBS: Very well. Mr. McWhirter.

MR. McWHIRTER: Mr. Chairman, this case is a matter of great and extraordinary importance at this point in time in the history of Florida. We are beyond the threshold of the competitive wholesale market for electricity. You have carefully monitored that market and require each utility to annually report on its wholesale transactions from the previous year and to provide its forecasted costs for the coming year.

In 1996, the Public Counsel expressed concern about the treatment of revenues received from wholesale sales. And in that case he argued that the fuel costs should be credited with the actual cost of fuel on wholesale sales rather than the amount of money that the utility received. The Commission took that under consideration, had extensive hearings on it, and in 1997 you issued a policy and the policy distinguished between nonseparated sales and separated sales. And you established procedures to be followed with each type of sale for the protection of customers.

And here is what you said in that order. You said, "We have a long history of providing utilities with the flexibility needed to maximize retail benefits. However, a utility bears the burden of showing that deviation from established policy is in the public interest. Thus, utilities shall credit average system fuel revenues through the fuel adjustment clause unless it demonstrates on a case-by-case basis that each new sale does, in fact, provide overall benefits to retail ratepayers."

And what we are saying there is that we have got this bifurcated situation in Florida today where you have a regulated industry that is venturing out into a competitive wholesale market and it has got potentially very serious problems. The problems being that the retail consumer should not be required to subsidize wholesale sales, and that retail customers are the ultimate beneficiaries of these transactions when the regulated utility's assets are used in these transactions.

There is also another very significant aspect, and that is in modern times we have affiliated or utility companies with affiliated sister or brother companies that engage in business transactions with the regulated utility, and those are wholesale transactions. And you need to monitor and be sure that those are sound transactions and that the retail consumers are well protected.

In this case we have found that three of the investor-owned utilities, Florida Power and Light, Florida Power, and Gulf Power have sold power from its own generators for a profit that is then passed through to the customers. These three bought power in the wholesale market for less than it cost them to generate it with their own generators and they passed the benefits of those transactions along to the customers.

But one utility, however, had a vastly different experience, and that utility, Tampa Electric, in the recent past hasn't had sufficient capacity to meet its retail customers needs. It bought power for far more than it cost to produce that power, and it gave that cost to the retail customers. It sold power for less than average cost in some instances, and it credited the retail customers not with the cost of the fuel that was burned, but the price that was received for the sale of the power. And it will be argued here today that that is in keeping with the Commission's philosophy.

But I think we will show that it may be, but there is inadequate evidence, substantial compete evidence in this proceeding filed so far to justify that circumstance.

The result of the transactions by Tampa Electric in the years 2000 and 2001 from their wholesale transactions related in an underrecovery of $88 million. Tampa Electric is asking you in this proceeding to have its current customers, retail customers pick up that tab. It is the tab on wholesale transactions gone awry at a time when Tampa Electric was selling its own generation in the retail market at a low cost, it was buying back power at a high price from the wholesale market.

We have attempted to delve into the circumstances of this case. Tampa Electric says it has responded to each of our questions. We started asking questions in February of 28th of 2001, nearly ten months ago. And we went through a series, a lot of information was supplied, a lot was deemed confidential. And that is understandable and necessary when you are trying to protect competitive interests. It is somewhat more questionable and gives you more concern when you are trying to protect transactions between affiliated companies and the regulated utility company.

It was necessary to have hearings on motions for protective orders, to have hearings on objections to discovery. And our last discovery was given to us in response to a

Commission order that was rendered yesterday and it was given to us this morning. And it has information of a -- confidential information of great significance relating to wholesaling affiliated company transactions that needs to be explored.

We are not saying that Tampa Electric is guilty of any wrongdoing. We are just saying that when we do a rifle focus on the circumstances of these transactions, $88 million on a utility this size as losses primarily in wholesale transactions in a two-year period is certainly an eyebrow raiser.

Because of that we invited experts to come and examine these wholesale transactions, well-known professional consultants from St. Louis came. They asked these questions that we had slowly got the information on, some we got rapidly, but they couldn't perform, nor should they perform a full audit of the transactions. What we asked them to do was to smell the smoke and see if there was fire or something that pretended to be unfair to the retail consumers, because the mission of this Commission is to protect retail consumers.

You will hear in today's testimony what these people have found. It will be criticized because it is not a thorough audit. We didn't intend a thorough audit. All we ask in this case is that the Commission determine that there is enough smoke to indicate that it, yourselves and your staff, should undertake a full examination of this $88 million surcharge that is being imposed upon the retail consumers. And a lot of it is confidential and we hope that your staff will probe it thoroughly.

And we think this is important because what is happening in this case between Tampa Electric Company, a load serving utility, and its affiliated merchant plant company is kind of what is going to happen in the future. It's like Mr. Deason was discussing earlier today with cost-recovery clauses and the competition market coming, we need to be careful. And what you need to be careful about is what you said you would be careful about in an order issued by Mr. Deason, Mr. Garcia, and Julia Johnson back in '97. And he said Mr. Ramil, who was then an expert witness for Tampa Electric, and now its president, raised concerns regarding a potentially burdensome review and the danger of such a review becoming an opportunity for increased litigation. Nonetheless, the Commission said, it is the Commission's responsibility to ensure that activities taking place in the wholesale market do not adversely affect retail consumers.

We think there is smoke coming out under the eves of the Tampa Electric facade. And we are very concerned that there may be -- where there is smoke we may find things that are adversely affecting retail customers. Our experts say that that number is somewhere -- in the past three years, somewhere between 45 and $108 million that conceivably retail consumers have been overcharged essentially through these wholesale transactions. That is an appalling number and one we think deserves serious, very serious consideration by your Commission.

And I thank you for your attention and we will look forward to going through the case with you.

CHAIRMAN JACOBS: Thank you. Mr. Cloud.

MR. CLOUD: Yes, sir. My client, Publix, is one of the largest, if not the largest Florida-based competitive companies. It is headquartered, ironically, in my hometown of Lakeland. It has been in business for 70 years. It is now operating in four states. Interestingly enough, their experience in power costs and reliability show Florida at the bottom of the list in the other states they operate in.

And to a company that is no stranger to one percent margins in the very highly competitive field of grocery market, power costs are a major impact to Publix and to its customers. They have a duty to their stockholders, which I'm sure if you are from Florida you know includes their employees, and a duty to their customers to keep prices low. If Publix isn't competitive, then the stockholders and the employees bear that burden. And if we sign contracts, even though lawful, even though upheld by every agency in the land and they turn out to be less than profitable, the market puts a check on that inequitable allocation between the stockholders and the customers. If we try and raise prices too much, we lose business.

And in this proceeding you are the market. You are there to serve as the watchdog and to look into these issues. And I think as FIPUG has said today, whose position we support, there is more than just the hint of smoke there. Now, in this hearing you are going to hear a number of things about how FERC has approved this and the contracts are valid and you approved the contracts. This hearing isn't about whether or not the Federal Energy Regulatory Commission said that the separated contracts were lawful or okay for purposes of those proceedings or whether the contracts were good or bad in the past. It is not about whether TECO inappropriately charged purchased power back then. It is a question today of fairly allocating both the good and the not so good decisions between stockholders and customers and you take the place of the market.

Now I know we are late to this proceeding and we take it as we find it, and this may be our first appearance before the Commission, but I promise you that until our company is able to see a change in the way rates are structured for the major IOUs in this state where they are more in line with what we see in other states, it probably won't be our last appearance. And we appreciate your indulgence for our opening statement. Thank you.

CHAIRMAN JACOBS: Thank you.

MR. BEASLEY: Commissioners, some things never change. Two years ago this week in this room we heard Mr. McWhirter characterize the witness of his -- or the testimony of his witness, he said, Mr. Chairman, and I quote, if you read the testimony on Page 6, essentially he is saying that he sees smoke by the OSHA report. He doesn't suggest the Commission rely on the OSHA report in any way with respect to these findings, what he does -- because he has seen the smoke and there is evidence of fire, he says, "I recommend the Commission disallow the fuel replacement costs until TECO comes forward with clear and convincing evidence."

Commissioners, the terms disallow, and postpone, and further investigate, and defer are common in the FIPUG vocabulary. We are confident, and we believe by the conclusion of this hearing that you will be satisfied that Tampa Electric is in full compliance with your regulatory practices and requirements regarding separated and nonseparated wholesale sales. The evidence will show, contrary to FIPUG's assertion, that Tampa Electric does not allocate, for example, 100 percent of its purchased power costs to its retail customers. Instead, the company fairly allocates its fuel costs, all of them, including the purchased power costs, to both its retail and wholesale customers in proportion to the megawatt hours each group uses.

The record will also show, contrary to FIPUG's contention, that all but one of its current separated wholesale sales are charged on a system average fuel cost basis, exactly the way FIPUG's witnesses say it should be done. The one separated sale that is not charged on a system average fuel cost basis is the unit power sale out of Big Bend Unit 4 to TECO Power Services Corporation. And that particular transaction was one of among four contracts specifically approved by the Commission in the Hardee Power Station need determination case. And you will recall that project was approved because the Commission found that the contracts comprising it would save the customers of Seminole Electric Cooperative some $37 million, and the customers, the retail customers of Tampa Electric approximately $90 million.

Tampa Electric has submitted solid evidentiary support for its proposed factors, and its costs and its operations have been carefully reviewed by your staff. As against this, you will see that FIPUG's case relies upon a flawed study that draws erroneous conclusions from the data included in Tampa Electric's monthly A Schedules that are filed with this Commission.

The evidence will show that in their haste to find a subsidy that doesn't exist, FIPUG's witnesses have simply been mistaken in their attempted analysis of those monthly A Schedule filings. Finally, as regards FIPUG's allegations concerning delay, we were very circumspect in even objecting to FIPUG's discovery. We have timely provided FIPUG with an unprecedented volume of discovery material and responses. Most all of the grounds for the timely objections that we did make were sustained, and the ones that weren't were promptly answered consistent with the expedited schedule prescribed by the prehearing officer.

Tampa Electric was proactive in attempting to get confidential information into FIPUG's hands early on. As early as May the 8th of this year, we approached FIPUG with a nondisclosure agreement, something that the prehearing officer ultimately concluded FIPUG would need to execute in order to have access to confidential information. We approached them, it fell on deaf ears. We did this three separate times in written proposals to enter into with them with a nondisclosure agreement.

It was only in late August when FIPUG saw that the deadline for filing intervenor testimony looming on the horizon that they suddenly realized that they needed to sign a nondisclosure agreement to get this information. We did that immediately with them and immediately turned over the confidential information that we were duty bound to protect for our ratepayers' benefit until such time as FIPUG agreed to sign the nondisclosure agreement.

Even then with the confidential information in hand, FIPUG ultimately determined that it was only going to rely on the A Schedules, which are not confidential. So they had all along and have had monthly every year, year in and year out the information that their experts ultimately relied on in putting together their study. So any delay that FIPUG complains of is delay, we submit, that is attributable to FIPUG's own actions, or in the case of the nondisclosure agreement, their inactions.

FIPUG has alleged delay on the part of Tampa Electric we believe in an unfair effort to cause additional delay in the setting of Tampa Electric Company's cost-recovery factors for 2002. And the evidence you will hear today will demonstrate that FIPUG has offered no justification whatsoever for any further delay, or further review, or any of the other true-up avoidance tactics that FIPUG may have in its portfolio.

Their goal of delaying the Commission's approval of the implementation of our new fuel cost recovery factors in January 2002 is consistent with the approach they took two years ago and in other proceedings where an increase is proposed or some change to the upside in a fuel factor, or a rate or a charge that is being proposed. While it may be consistent with their prior approaches in this regard, it doesn't justify that approach, and we would ask that you turn away FIPUG's efforts to delay this even further. And that concludes our opening statement.

CHAIRMAN JACOBS: Very well. And if there is nothing else as a preliminary matter, we are prepared to swear the witnesses. Anything else? Would all the witnesses who will testify in this docket please stand and raise your right hand.

(Witnesses collectively sworn.)

Thank you very much. You may proceed. And I believe the first witness is TECO.

MR. BEASLEY: I call J. Denise Jordan to the stand.

J. DENISE JORDAN

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Jordan, could you please state your name, your business address, and your position with Tampa Electric Company?

A J. Denise Jordan, 702 North Franklin Street, Tampa, Florida 33602, director of Rates and Planning.

Q Ms. Jordan, did you prepare and submit in this proceeding a document entitled prepared direct testimony of J. Denise Jordan dated April 21, 2001?

A Yes, I did.

Q Did that reflect your --

CHAIRMAN JACOBS: Excuse me, Ms. Jordan is your red light on there. Off. Is the red light off? There you go.

Thank you.

BY MR. BEASLEY:

Q And that was your 2000 true-up testimony?

A That is correct.

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

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Jordan's April 21, 2001 testimony be admitted into -- or be copied into the record as though read.

CHAIRMAN JACOBS: Very well. Without objection show Ms. Jordan's -- I'm trying to make sure I have the right one here. Ms. Jordan's testimony is entered into the record as though read.

BY MR. BEASLEY:

Q Ms. Jordan, was the Exhibit JDJ-1 consisting of 230 pages that accompanied that testimony prepared under your direction and supervision?

A Yes, it was.

MR. BEASLEY: I would ask that Ms. Jordan's Exhibit JDJ-1 be marked for identification.

CHAIRMAN JACOBS: Show that marked as Exhibit 1.

(Exhibit 1 marked for identification.)

BY MR. BEASLEY:

Q Ms. Jordan, did you submit prepared direct testimony dated August 20, 2001, that relating to the 2001 estimated and actual true-up?

A Yes.

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

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Jordan's August 20, 2001 prepared testimony be inserted into the record as though read?

CHAIRMAN JACOBS: Without objection show that testimony is entered into the record as though read.

BY MR. BEASLEY:

Q Ms. Jordan, the 23-page exhibit identified as Exhibit JDJ-2 that accompanied that August 20 testimony, was that prepared under your direction and supervision?

A Yes, it was.

MR. BEASLEY: I would ask that that exhibit be marked for identification.

CHAIRMAN JACOBS: Show it marked as Exhibit 2.

(Exhibit 2 marked for identification.)

BY MR. BEASLEY:

Q Ms. Jordan, did you submit the prepared direct testimony of J. Denise Jordan dated September 20, 2001, that relating to the 2002 projection filing?

A Yes.

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

A Yes, they would.

MR. BEASLEY: I would ask that that set of testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection show the testimony dated 9/20 is entered into the record as though read.

BY MR. BEASLEY:

Q Ms. Jordan, the exhibit that accompanied that testimony, JDJ-3, was that prepared under your direction and supervision?

A Yes, it was.

MR. BEASLEY: I would ask that that exhibit be marked for identification.

CHAIRMAN JACOBS: Show it marked as Exhibit 3.

MR. BEASLEY: I'm sorry, sir.

CHAIRMAN JACOBS: Show it marked as Exhibit 3.

MR. BEASLEY: Thank you.

(Exhibit 3 marked for identification.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 4/02/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT 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") in the position of Director, Rates and Planning in the Regulatory Affairs Department.

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working for Florida Power Corporation in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In

February 2001, I was promoted to Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power cost recovery filings, capacity cost recovery filings, environmental cost recovery filings and energy and rate design issues and analyses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Florida Public Service Commission's ("FPSC" or "Commission") review and approval, the net true-up amounts for the period from January 2000 through December 2000 for both the Fuel and Purchased Power Cost Recovery and the Capacity Cost Recovery Clauses. I also present the wholesale incentive benchmark for January 2001 through December 2001.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. 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.

Q. Have you prepared an exhibit in this proceeding?

A. Yes. I have prepared Exhibit No.___ (JDJ-1), Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery which contains four documents as described in my testimony.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period January 2000 through December 2000?

A. The net true-up amount is an under-recovery of $589,079.

Q. Please explain Document No. 1.

A. Document No. 1, page 1 of 4 entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2000 through December 2000" shows the calculation of the final net true-up under-recovery amount of $589,079. The actual capacity cost over-recovery, including interest was $1,388,160 for the period January 2000 through December 2000 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the actual/estimated over-recovery approved in FPSC Order No. PSC-00-2385-FOF-EI issued December 12, 2000 in Docket No. 000001-EI of $1,977,239, results in a final under-recovery for the period of $589,079 as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2002 through December 2002.

Q. What is the estimated effect of this $589,079 under-recovery in the January 2000 through December 2000 period, on residential bills during the January 2002 through December 2002 period?

A. The $589,079 under-recovery will cause a typical 1,000 kWh residential bill to be approximately $0.03 higher.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Q. What is the net true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2000 through December 2000?

A. The net fuel true-up is an under-recovery of $23,129,476.

The actual fuel cost under-recovery, including interest, was $65,850,797 for the period January 2000 through December 2000. This $65,850,797 amount, less the actual/estimated under-recovery amount of $42,721,321 approved in Order No. PSC-00-2385-FOF-EI issued December 22, 2000 in Docket No. 000001-EI results in a final under-recovery amount for the period of $23,129,476. This under-recovery amount will be applied in the calculation of the fuel recovery factors for the period January 2002 through December 2002.

Q. What is the estimated effect of this under-recovery in the January 2000 through December 2000 period on residential bills during the January 2002 through December 2002 period?

A. The $23,129,476 under-recovery will cause a typical 1,000 kWh residential bill to be approximately $1.31 higher.

Q. Please explain Document No. 2.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel Over/(Under)- Recovery for the Period January 2000 through December 2000." It shows the calculation of the final fuel under-recovery for the period of $23,129,476, which will be applied in the calculation of the fuel and purchased power cost recovery factors for the period January 2002 through December 2002.

Line 1 shows the total company fuel costs of $460,988,973 for the period January 2000 through December 2000. The jurisdictional amount of total fuel costs is $444,626,080 as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $71,996,760 under-recovered fuel costs for the period, combined with the interest, true-up collected and the prior period true up shown on lines 5, 6 and 7, respectively, constitute the actual under-recovery of $65,850,797 shown on line 8. The $65,850,797 less the actual/estimated under-recovery of $42,721,321 shown on line 9, which was approved in FPSC Order No. PSC-00-2385-FOF-EI, results in the final under-recovery of $23,129,476 as shown on line 10.

Q. Please explain Document No. 3.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original

Estimates for the Period January 2000 through December 2000," shows the calculation of the actual under-recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period January 2000 through December 2000?

A. As shown on line C3 of Document No. 3, the company collected $5,807,585 or 1.5 percent less jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period January 2000 through December 2000?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $53,402,438 or 13.1 percent more than originally estimated.

Q. Please explain Document No. 4.

A. Document No. 4 contains Commission Schedules A-1 through A-9 for the months of January 2000 through December 2000. Also included is a twelve-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, and A9 for the period January 2000 through December 2000.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2001?

A. The company's 2001 benchmark is $4,768,644, which is the three-year average of $9,450,622, $2,273,119 and $2,582,191 actual gains on the non-separated wholesale sales, excluding emergency, for 1998, 1999 and 2000, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 8/20/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT 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") in the position of Director, Rates and Planning in the Regulatory Affairs Department.

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working for Florida Power Corporation in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In

February 2001, I was promoted to Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power, capacity, environmental and energy conservation cost recovery clauses, and rate design and analyses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2001 through December 2001 fuel and purchased power and capacity true-up amounts to be recovered in the January 2002 through December 2002 projection period. My testimony addresses the recovery of fuel and purchased power costs and capacity costs for the year 2001, based on six months of actual data and six months of estimated data. This information will be used to determine fuel and purchased power cost and capacity cost recovery factors for the year 2002.

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

A. Yes. I have prepared Exhibit No. ____ (JDJ-2) which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-5, E-6, E-7, E-8, and E-9 which provides the actual/estimated fuel and purchased power cost recovery true-up amount for the period of January 2001 through December 2001. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2001 through December 2001. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2002 through December 2002 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2001 through December 2001 is an under-recovery of $88,672,735, which includes $55,497,225 of the company's estimated mid-course correction under-recovery to be recovered in 2002 as filed by the company on February 9, 2001 in this docket.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2002 through

December 2002 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2002 is the sum of the final true-up amount for the period of January 2000 through December 2000 and the actual/estimated true-up amount for the period of January 2001 through December 2001.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2000?

A. The final 2000 true-up is an under-recovery amount of $23,129,476 as shown in both Tampa Electric's February 9, 2001 mid-course correction and April 2, 2001 true-up filings.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2001 through December 2001?

A. The actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $65,543,259. The detailed calculation supporting the actual/estimated true-up is shown in Exhibit ____ (JDJ-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2002 through December 2002 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2001 through December 2001 is an under-recovery of $5,560,103 as shown in Exhibit ____ (JDJ-2), Document No. 2, page 2 of 3.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2002 through December 2002 capacity cost recovery factors?

A. Tampa Electric calculated the net true-up amount to be recovered in 2002 in the same manner as previously described for the fuel and purchased power cost recovery net true-up amount. The net true-up amount to be recovered in the 2002 capacity cost recovery factors is the sum of the final true-up amount for 2000 and the actual/estimated true-up amount for January 2001 through December 2001.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2000?

A. The final true-up amount is an under-recovery of $589,079 per the company's April 2, 2001 true-up filing and as shown in Exhibit ____ (JDJ-2), Document No. 2, page 1 of 3.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2001 through December 2001?

A. The actual/estimated true-up amount is an under-recovery of $4,971,024 as shown on Exhibit ____ (JDJ-2), Document No. 2, page 1 of 3.

Q. Does this conclude your testimony?

A. Yes it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 09/20/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In February 2001, I was promoted to

Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power, capacity, environmental and energy conservation cost recovery clauses, and rate design and business analyses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors and the projected wholesale incentive benchmark for January 2002 through December 2002. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2002. In addition, I will address the regulatory treatment for expenses and revenues associated with hedging fuel and wholesale energy costs and capital projects that are expected to reduce long-term fuel costs. Finally, I will address the appropriateness of offsetting excess earnings by reducing the amount of prudently incurred fuel and purchased power expenses recovered through the clause.

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

A. Yes. My Exhibit No. ____ (JDJ-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1 of Exhibit No. ____ (JDJ-3) is furnished as support for the projected capacity cost recovery factors. In support of the proposed levelized fuel and purchased power cost recovery factors, Document No. 2 is comprised of Schedules E-1 through E-10 for January 2002 through December 2002 and Schedule H-1 for January through December, 1999 through 2002. Document No. 3 provides the projected 1999 earnings refund by rate schedule. Document No. 4 provides the composite effect of the proposed cost recovery factors on a 1,000 kilowatt-hour ("kWh") residential bill.

Capacity Cost Recovery Clause

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ___ (JDJ-3), Document No. 1, Projected Capacity Cost Recovery.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery through the capacity cost recovery factor of capacity payments for purchases of power made for retail customers excluding optional provision purchases for interruptible customers.

Q. Please summarize the proposed capacity cost recovery clause factors by rate schedule for January 2002 through December 2002.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kWh)
Average Factor	0.296
RS	0.379
GS and TS	0.350
GSD, EV-X	0.269
GSLD and SBF	0.245
IS-1, IS-3, SBI-1, SBI-3	0.022
SL-2, OL-1 and OL-3	0.041

These factors are shown in Exhibit No. ___ (JDJ-3), Document No. 1, page 3 of 3.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.296 cents per kWh compare to the factor for 2001?

A. The proposed capacity cost recovery factor is 0.097 cents per kWh (or $0.97 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.199 cents per kWh for the January 2001 through December 2001 period.

Fuel and Purchased Power Cost Recovery Factors

Q. What is the appropriate value of the base fuel and purchased power cost recovery factor for the year 2002?

A. The appropriate value for the new period is 3.301 cents per kWh before the normal application of factors that adjust for variations in line losses. Schedule E-1 of Exhibit No. ___ (JDJ-3), Document No. 2, Fuel Projection, shows the appropriate values for the total fuel and purchased power cost recovery factor as projected for the period January 2002 through December 2002.

Q. Please describe the information provided on Schedule E-1C.

A. The GPIF and true-up factors are provided on Schedule E-1C. Tampa Electric has calculated a GPIF reward of

$1,095,745 which is to be included in the calculation of the total fuel and purchased power cost recovery factors.

Additionally, E-1C indicates the net true-up amount for the January 2001 through December 2001 period. The net true-up amount for this period is an under-recovery of $88,672,735.

Q. Please describe the information provided on Schedule E-1D.

A. Schedule E-1D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2002 through December 2002.

Q. What is the purpose of Schedule E-1E?

A. The purpose of Schedule E-1E is to present the standard, on-peak and off-peak fuel adjustment factors after adjusting for variations in line losses.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by rate schedule for January 2002 through December 2002.

A.

Rate Schedule	Fuel Charge Factor (cents per kWh)
Average Factor	3.301
RS, GS and TS	3.313
RST and GST	4.535 (on-peak)
	2.793 (off-peak)
SL-2, OL-1 and OL-3	3.054
GSD, GSLD, and SBF	3.304
GSDT, GSLDT, EV-X and SBFT	4.523 (on-peak)
	2.786 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	3.232
IST-1, IST-3, SBIT-1, SBIT-3	4.425 (on-peak)
	2.725 (off-peak)

Q. How does Tampa Electric's proposed average fuel adjustment factor of 3.301 cents per kWh compare to the average fuel adjustment factor for the April 2001 through December 2001 period?

A. The proposed fuel charge factor is 0.481 cents per kWh (or $4.81 per 1,000 kWh) higher than the average fuel charge factor of 2.820 cents per kWh for the April 2001 through December 2001 period.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2002?

A. The company's projected 2002 benchmark is $2,283,019, which is the three-year average of $2,273,119, $2,582,191 and $1,993,747 in gains on the company's non-separated wholesale sales, excluding emergency, for 1999, 2000 and 2001 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2002 from non-separated wholesale sales to exceed its 2002 wholesale incentive benchmark?

A. No. Tampa Electric does not anticipate exceeding the projected benchmark; therefore, 100 percent of the gains will flow back to ratepayers.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2002 Fuel and Purchased Power and Capacity Cost Recovery projections that were not reflected in last year's projections?

A. Yes. There are four significant events. These are 1) the deferred estimated mid-course correction under-recovery of $55.5 million to be recovered in 2002, 2) the new purchased power agreements including the leasing of self-contained portable generators, 3) operational events at Big Bend and Gannon Stations, and 4) the refund associated with Docket Nos. 950379-EI and 960409-EI.

Q. Please describe the first event that impacts the company's projection filing.

A. On February 9, 2001, the company filed for a mid-course correction of its fuel and purchased power fuel factors. The company expected its fuel and purchased power total under-recovery through December 31, 2001 to be $86,335,390, which included the 2000 final true-up under-recovery of $23,129,476 and the January through December 2001 estimated reforecasted under-recovery of $63,205,914. The company proposed that the correction be based on approximately 50 percent of the $63,205,914 under-recovery being recovered during the April 2001 through December 2001 period. The remainder of the under-recovery and the 2000 final true-up, a total of $55,497,225 is being recovered in the January 2002 through December 2002 period. This comprises a significant portion of the company's total under-recovery.

Q. Please describe the second event that impacts the company's projection filing.

A. In an effort to improve system reliability for retail ratepayers in 2001, 2002 and beyond at reasonable and prudent costs, Tampa Electric explored numerous options. As a result, the company negotiated new purchased power agreements and also contracted to lease self-contained portable generators. The direct testimony of Tampa Electric witness W. L. Brown describes these purchases and the lease contract, and demonstrates that the costs associated with these purchased power agreements and leases are prudent and appropriate for recovery through the Fuel and Purchased Power and Capacity Cost Recovery Clauses.

Q. Please describe the third event.

A. As described in the direct testimony of Tampa Electric's witness M. J. Hornick, the company has experienced increased needs for purchased power in 2001 due to extended outages as a result of environmental constraints at Big Bend Station and an infestation of non-indigenous green lip mussels in Tampa Bay which impacted operation at Gannon Station. In addition, due to the tie-in work for the repowering of Gannon Station, the company has negotiated several new firm capacity and energy purchases to meet desired operating reserves which will impact purchased power and capacity costs for 2002.

Q. Please describe the fourth event.

A. The fourth event relates to the refund contemplated in Order No. PSC-96-1300-S-EI from Docket No. 960409-EI. The Order specifies that the total refund associated with 1999 earnings is to be provided to customers at a rate of $2 million per month until the entire refund is exhausted. The refund is to be reflected as a credit on customers' bills calculated by multiplying a levelized factor adjusted for line losses times the actual kWh usage for the period of the refund. The refund is to include interest on the unamortized amount of the refund.

Pending the direction of the Standard Order to be issued in Docket No. 950379-EI due November 26, 2001, the company expects that the total amount to be refunded is $6.37 million, which includes interest through December 31, 2001. This amount will be refunded to customers beginning in January 2002 at a rate of approximately $2 million per month over a three-month period. This is shown in Exhibit___(JDJ-3), Document No. 3.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power and environmental cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is an increase of $6.15 beginning January 2002. These charges are shown in Exhibit___(JDJ-3), Document No. 4.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with the first billing cycle for January 2002.

Regulatory Treatment- Hedging

Q. What is the appropriate regulatory treatment for gains and losses from hedging an investor-owned electric utility's fuel transactions through futures contracts?

A. If Tampa Electric were to take any offsetting financial positions to insulate ratepayers from fluctuations or to levelize fuel costs and wholesale energy prices, the associated revenues and expenses that result from the hedging transactions should be flowed through the fuel and purchased power cost recovery clause. The benefactors of Tampa Electric employing a strategy of entering into exchange-based derivatives, forward contracts or insurance to stabilize prices are the ratepayers; therefore, ratepayers should receive the benefits of any gains and be responsible for any losses resulting from hedging fuel transactions through futures contracts.

Q. What is the appropriate regulatory treatment for the premiums received and paid for hedging an investor-owned electric utility's fuel transactions through options contracts?

A. As I previously stated, revenues and expenses that result from hedging transactions that Tampa Electric enters into to insulate ratepayers from fluctuations or to levelize fuel and wholesale energy costs should be recovered through the fuel and purchased power cost recovery clause. This includes the premiums received and paid for hedging fuel transactions through options contracts.

Q. What is the appropriate regulatory treatment for the transaction costs associated with an investor-owned electric utility hedging its fuel transactions?

A. All transaction costs associated with hedging fuel and wholesale energy costs to help avoid or limit the risk of price fluctuations for the benefits of our ratepayers should be recovered through the fuel and purchased power cost recovery clause.

Regulatory Treatment- Capital Expenditures

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

A. Tampa Electric is not seeking recovery of any capital expenditures for projects with an in-service date on or after January 1, 2002 that are expected to reduce long-term fuel costs. However, if the company were to seek recovery for such capital projects, the appropriate regulatory treatment would be to recover the costs of the investments and the associated carrying costs through the fuel and purchased power cost recovery clause.

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. As previously stated, Tampa Electric is not seeking recovery of any capital expenditures for projects with an in-service date on or after January 1, 2002 that are expected to reduce long-term fuel costs. However, if the company were to seek recovery for such capital projects, the appropriate rate of return on the unamortized balance would be the mid-point of the company's allowed return on equity range approved by the Commission during the company's last rate case.

Regulatory Treatment - Over-earnings

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

A. Whether the Commission can legally reduce a utility's recovery of prudently incurred fuel and purchased power costs to offset over-earnings is a legal issue the resolution of which could depend upon the facts and circumstances of any such action. As a matter of policy, the Commission should not deduct any over-earnings from prudently incurred fuel and purchased power costs that are otherwise recoverable through the fuel adjustment mechanism. The fuel and purchased power cost recovery mechanism and base rates are two entirely different ratemaking concepts. The fuel adjustment clause was designed to accommodate volatility in fuel prices and to effect a nonprofit, dollar for dollar recovery of fuel costs. Base rates, on the other hand, are fixed over time based on a representative test period and are intended to allow for the recovery, within a range, of the nonfuel related costs of providing electric service, including a reasonable return on the utility's invested capital.

Mixing the fuel adjustment mechanism with base rates would cause nothing but confusion, delay and inequity. This would defeat the very purpose of the fuel adjustment clause. The Legislature has a prescribed procedure for handling situations where a party contends a utility is earning above or below the range of reasonableness of its authorized rate of return. That procedure is set forth in Section 366.071, Florida Statutes, and has been used effectively by the Commission together with its continuing surveillance program to assert jurisdiction over earnings claimed to be higher than the utility's authorized range.

Over-earnings do not render prudently incurred fuel costs imprudent, any more than under-earnings legitimize imprudent fuel costs. Deducting alleged over-earnings from prudently incurred and otherwise recoverable fuel and purchased power costs makes no more sense than artificially surcharging customers through the fuel adjustment mechanism to make up for under-earnings a utility might experience.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Jordan, could you please summarize your prepared direct testimonies?

A Good afternoon, Commissioners. My direct testimony presents for Commission review and approval the proposed annual capacity cost-recovery factors, the proposed annual levelized fuel and purchased power cost factors and the projected wholesale incentive benchmark for January 2000 through December 2002. Because the issue of the jurisdictional cost-recovery for fuel and purchased power have become a significant issue in this docket, I think it would be helpful to focus a moment on the Schedules E1 and E2 in Document Number 2 of my Exhibit JDJ-3. Line 11 of Schedule E2 demonstrates the use of an energy jurisdictional separation factor. This factor is calculated on a monthly basis and is applied to the total fuel and net power transaction costs.

COMMISSIONER DEASON: Excuse me. You referred to us what?

THE WITNESS: To my projected testimony Exhibit JDJ-3, Document Number 2.

CHAIRMAN JACOBS: Schedule E2?

THE WITNESS: Yes, Line 11.

COMMISSIONER DEASON: And this accompanies which of your -- you had three testimonies, it accompanies which testimony?

THE WITNESS: The projected 2002.

COMMISSIONER DEASON: What date was that filed?

CHAIRMAN JACOBS: 9/20.

THE WITNESS: That was filed September 20th on Page 29.

COMMISSIONER DEASON: Okay. Thank you.

THE WITNESS: This factor is calculated on a monthly basis and is applied to the total fuel and net power transaction costs for each month to determine the appropriate amount of cost to be assigned to the retail jurisdiction. For 2002, retail customers were appropriately assigned approximately 94 percent of the total fuel and purchased power costs. The remaining 6 percent of the total fuel and net power transactions cost is assigned to the company's wholesale separated customers. Tampa Electric's wholesale customers are assigned their pro rata share of Tampa Electric's total fuel and net power transaction costs in the exact same ratio of their megawatt hour purchases to Tampa Electric's total megawatt hour sales.

Furthermore, on Schedule E1, Line 29, in my testimony that is Page 24, it shows the removal of the fuel and purchased power costs of separated wholesale sales from the system total, which results in the fuel and purchased power costs assigned to retail customers. These schedules demonstrate that wholesale customers are assigned a pro rata share of all costs which includes not only the costs of Tampa Electric's native generation, but purchased power costs, as well. Therefore, retail customers are not paying 100 percent of purchased power costs as alleged by FIPUG.

Schedule E1 also shows the relative costs on a cents per kWh basis assigned to retail customers and nonjurisdictional wholesale customers. Column 3 of that schedule at Lines 19 and 30 shows that the retail and wholesale customers are assigned approximately the same costs per kWh. This should alleviate any concern that wholesale customers might be receiving the benefits of more efficient or less costly generation. Tampa Electric has correctly assigned fuel and purchased power expenses to the retail jurisdiction and respectfully requests that the Commission approve Tampa Electric's recovery of its prudently incurred costs.

That concludes my summary.

MR. BEASLEY: We tender Ms. Jordan for questions.

MR. VANDIVER: No questions.

CHAIRMAN JACOBS: Mr. McWhirter. I'm sorry, we will go in order. Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Jordan, let's go first to the Schedule E1 that you discussed. And you went to Line 29, and that is your wholesale megawatt hour sales. And you sold 1,179,208 megawatt hours of wholesale sales?

A That is correct.

Q And then in addition to that if you look at Lines 13, 15, and 17, you sold another 775,753 megawatt hours, is that correct?

A Yes, of nonseparated sales.

Q So in Line 15 where it says fuel costs of Schedule D HPP sales, separated, that is a nonseparated sale?

A That is a separated sale. That is a separated sale that came before the Commission and was approved to have treatment other than system average.

Q All right. I will get back to that in a minute. With respect to Schedule D sales, these sales were not separated as they were in the 1993 rate case that you addressed or that has been filed as a document of which we take officially notice?

A Are you referring to Line 13?

Q Yes.

A That is a sale that is made to Seminole Electric which is for the benefit of a nonfirm retail customer.

Q Line 13, the Schedule D sale is a sale to Seminole Electric?

A Correct. That is wheeled then to Peace River Co-op that I think ultimately is provided to one of your FIPUG members.

Q And you charge $14.68 for that sale?
A Correct.
Q Now, with respect to the sales that we have just mentioned, are those sales charged to average fuel costs?
A Which sales that we just -- we talked about a lot of sales.
Q The ones that appear on Lines 13, 15, and 17.
A The lines that are market-based sales are charged whatever the market will bear.
Q I see.
A The HPP sale is a unit sale that Mr. Beasley referred to earlier. And the other sale on Line 13, as I mentioned, is really a territorial arrangement for a nonfirm retail customer, so it is based on a retail rate.
Q All right. With respect to Line 15, the sales to HPP, is that Hardee Power Partners?
A That is correct.
Q And Hardee Power Partners is an affiliated company of Tampa Electric Company?
A That is correct.
Q And you sold 486,000 megawatt hours to that entity?
A Yes.
Q And you charged $25.62 a megawatt hour?
A Correct.
Q And in this case you are seeking to set a fuel factor

for retail customers of $33.01 a megawatt hour, is that correct?

A That is correct.

Q And that price has on top of it this GPIF adjusted for taxes. What is GPIF?

A The generation performance incentive factor.

Q And that is the testimony Mr. Keselowsky presented?

A Yes.

Q Is that the correct pronunciation?

A Close enough.

Q Close enough. And under that, as I understand the general theory is if you do a good job in running your most efficient units, the ones with the lowest heat rate, then Tampa Electric is entitled to a reward. Is that in essence what it is about?

A I take your word on that. Mr. Keselowsky is probably the better person to ask questions with regard to the GPIF.

Q You don't know the answer to that?

A I don't know the details, no, I don't.

Q Now, let's go up to Line 15, the Hardee Power sales. When you sell to Hardee Power, is that from a specific unit or is it from all units?

A The Hardee Power Partners is a Big Bend 4 sale.

Q And is Big Bend 4 one of your more efficient or less efficient units? You don't know?

A You're getting outside of my range.

Q I see. And do you know whether Big Bend 4 is used in Mr. Keselowsky's testimony in determining the GPIF reward?

A I would assume that since it is one of our largest units that it is probably in there.

Q All right. Now, is any portion of that million dollars you are seeking on Line 39 passed through to Hardee Power Partners? Does it -- it's a ratio of purchases to your total sales, does it bear its portion of the GPIF?

A I don't understand the question, I guess.

Q Well, you are charging customers a million dollars for the reward on the GPIF, as I understand that line. Do you charge Hardee Power Partners anything for GPIF? You don't know?

A I don't know. I'm not really sure what you're asking with regards to that.

Q You don't know what I'm asking you. Would you like me to repeat it?

A If you could rephrase it, it might be helpful.

Q All right. Customers under your derivation, calculation of the fuel factor are charged a million dollars, and that is divided up as 6/10th of a mill per kilowatt hour, or, I guess, that would be 61 cents a megawatt hour?

A Okay.

Q It may be 6 cents. Let's see. I think it is 61 cents. Is Hardee Power Partners charged 61 cents for each megawatt hour it purchases as a result of the GPIF reward?

A I don't see the correlation there. I mean, I don't know what would be special to charge Hardee as opposed to any other generation facility.

Q Can you answer the question yes or no?

A Then I would assume no.

Q All right. With respect to the $88 million, or, I guess, $4.99 a month for every thousand kilowatt hours consumed, does Hardee Power Partners, your affiliated company, pay any portion of that $88 million?

A The customers are responsible for the underrecovery as far as the generation. That is a sale that is being made, so it is actually reducing the requirement, the cost.

Q Well, as I understood this $88 million number on Line 33, that is a true-up, and that is an increase in the price charged to customers.

A That's correct. But the sale to Hardee has a benefit to the customers. Therefore, when you're looking at the total cost, you're taking your generation and you're taking the purchased power costs and then you are backing out what you are making on the sale. So actually that is a benefit to make those sales.

Q You're backing out the $25.62. But if you added the true-up factor to it, you would be backing out $26, wouldn't you?

A Why would you add a true-up factor to a sale? I'm missing where you're going.

Q Well, you indicated that your wholesale customers and your retail customers share in the purchased power costs, and I was wondering if any portion of that $4.99 a megawatt hour is charged to your affiliated company, Hardee Power Partners?

A It is no more charged to them than it is to any market-based sale that we make.

Q I see. Okay. Now, if you go to your Schedule A6 --

A Could you refer me to a document, please.

Q It's on Page 47 of your Exhibit 3.

A A6?

Q Yes, ma'am.

A E6, you mean?

Q E6. Did I say A6? I apologize. It's E6 when it is prospective, what you are going to do the next year?

A Correct. I just want to make sure I'm on the right page.

Q And A is what you did last year, is that right? Okay. Now, I notice that down near the bottom, right beyond December 2nd you have HPP, that is Hardee Power Partners, on Page 47?

A Yes.

Q And you collect as fuel costs from Hardee Power

Partners, $25.62, and that is carried forward to Line 15 of Schedule E1, correct?

A Yes. The summary that is down below is the same lines we just talked about on the E1 schedule.

Q Now, you also collect another 85 cents or so per megawatt hour from Hardee Power Partners, and I don't see that on Schedule E1. If that is money collected, why --

A That is the O&M piece. That is the O&M, the operation and maintenance piece that is credited to other operating revenues.

Q I see.

A Per the wholesale incentives docket.

Q So that means when you operate Big Bend 4 for every megawatt hour you produce it is about -- what is the difference between 36.10 and 25.62? I guess it is about 50 cents. That is 50 cents O&M, but you don't charge 50 cents O&M to the market-based sales which is on the next line down, is that right?

A The reason -- we do charge O&M, you don't see it, because on the Hardee, we started making those the same because of the change in the wholesale incentives docket, but we do charge an O&M piece that is credited to other operating revenues, it is just not reflected in the total cost.

Q Where does it show in your exhibit?

A It isn't here.

Q Can you provide any proof on what O&M is charged?

A Yes. You have asked us that in an interrogatory and we did provide that information.

Q You gave it in an interrogatory, but you haven't filed it in this docket?

A Right. Well, we filed it within the docket in the interrogatories.

Q Yes. It's not yet in evidence?

A Yes.

Q And with respect to that charge, does that flow through to the retail consumers or does that flow through above-the-line to Tampa Electric Company?

A Per the wholesale incentives docket for the calculation of the gains, the other operating revenues is flowed to Tampa Electric.

Q I see. Now, let's go over here to Schedule E7, and that is the electricity you're going to buy this year. And you are going to buy a million megawatt hours or more from your affiliated company, Hardee Power Partners, and you are going to charge --

MR. BEASLEY: Where are you referring to on that schedule, if you would, please.

MR. McWHIRTER: Go to Page 49, and look on the left-hand column. You will see the word through, and you see HPP, and we will see the number of megawatt hours that you purchased from your affiliated company.

BY MR. McWHIRTER:

Q And when you buy power, you charge Tampa Electric, the load serving utility, $46.19, but when you sell power you charge Hardee Power $25.62. And can you tell me whether it ever happens that those sales are occurring simultaneously, you're buying and selling at the same time?

A I would think we are. Mr. Brown could probably tell you for sure.

Q All right. Now, most of the utilities had a Schedule E1, and then they have a Schedule E1-B, and in that E1-B the utilities, all the utilities except your company explain how you come up with the true-up number that appears on Line 33. And it appears that you didn't have an E1-B at the time you filed your testimony.

A Could I refer you to my testimony from August 20th. I think the E1-B for the true-up within the period is filed within that testimony. Exhibit JDJ-2 filed August 20th, Document Number 1, does provide the E1-B, which shows the calculation of the $65,543,259 underrecovery for the period for 2001 in the actual estimated filing.

Q But the number here is $88 million.

A That includes the 23.1 million that was the final true-up from 2000.

Q So, the current year is 23 from 2000, and --

A And the current year of 65.5 million.

(Simultaneous conversation.)

CHAIRMAN JACOBS: Let's get one at a time talking, otherwise you get the court reporter in dire straits.

MR. McWHIRTER: I'm sorry.

BY MR. McWHIRTER:

Q Now, in that Schedule E1-B attached to your August 20th testimony, you have a breakdown between wholesale and retail customers. Can you show me where that breakout occurs?

A B1 is the megawatt hours associated for the retail jurisdiction. B2 are the megawatt hour sales associated for the separated wholesale sale. B4 is the energy jurisdictional separation factor which is applied monthly to result in the jurisdictional retail fuel recovery revenue.

Q All right. Now, so what we saw in December, you project in December that 97 percent of your sales will be for the retail market?

A Correct.

Q And what is the annual component, the average annual component?

A I don't know. I think it was 93, 94 percent on the annual. And for 2000 it is 94 percent.

Q But as I'm looking at E1-B, I don't see any entries as low as 94 percent, so the average must be more than 94 percent, isn't that correct?

A Are you asking me on a projected or what it actually ended up being?
Q Projected.
A I don't know what it was on projected, I'm sorry. I just have it monthly. On an actual basis I think it was in the neighborhood of 93.
Q When you do that percentage as wholesale sales, do you include the sales to Hardee Power Partners, your affiliated company?
A The E6 that we report, we report the nonseparated nonfirm sales, and we report also the Hardee sales, as well. So when we come up with the total costs we take the native generation costs, the purchased power costs, minus the sales, and then that is applied, that cost is allocated based on this energy factor for the retail piece.
Q So that --
A So the cost, the benefit of the sales, the benefit of the nonfirm sales and the benefit of the HPP sale, the market-based sales, all of those sales have been removed from the cost responsibility for the wholesale and for the retail.
Q Oh, I see. So those sales don't have any obligation to participate in the true-up on your --
A Those sales are lowering the overall system costs, therefore helping the retail customer.
Q But if you allocated some of the true-up to them,

they would lower it even more, wouldn't they?

A You're making the sale, you are making the sale in order to mitigate your costs that you are passing on to your retail customers, so they are helping to lower that underrecovery.

Q To the degree that you allocate. But if you allocated more they would help more, right?

A Correct. If you allocated more, yes, but then you may not be able to make the sale, or you may not get the benefit of like the $90 million that Mr. Beasley referred to earlier which justifies that are not shown anywhere on these schedules. There are other benefits that the A Schedules or the E Schedules would not pick up that are beyond fuel because it is a separated sale.

Q Now, that benefit was calculated in what year?

A '93. '92/'93, I guess.

Q In '93. And that is, what, nine years ago?

A Yes. But all that time the retail ratepayers have not had those costs in their rates. So regardless of when it was calculated, it was calculated going forward that we would not be responsible for those costs. So they have benefitted all of those years.

Q Let me -- when you say costs, are you talking about fuel costs or are you talking about --

A I'm talking about the fixed costs.

Q Fixed costs. So do all of your generating plants cost the same thing when you bought them? When they go into rate base, do they all go in at the same price?

A I'm sure they don't, sir.

Q Do some go in at a higher price than others, or do they all go in at the same price?

A I think we just established that they don't go in all at the same price, so some are high and some are low.

Q So when you separated Big Bend 4 and made the sale to Hardee, did you use the actual costs that related to that unit or did you use system average costs?

A I wasn't involved, but I would assume that based on pretty much Commission policy it was system average costs.

Q I see. So if the system average cost was $100 a kilowatt, and the Big Bend 4 costs $500 a kilowatt, I guess you have got to figure out how many megawatts it would be for the overall, but it would be somewhat less if that were your most expensive plant, wouldn't it?

A Possibly.

Q Uh-huh. But that information -- we are able to determine if we can have a full investigation of the current circumstances, wouldn't we?

A I'm not sure what information you are referring to when you make that statement.

Q Well, when you make the separation, you made a unit power sale, we can determine whether or not you have segregated from your rate base the value of that specific unit or if you used some average cost for all of your units?

A In order for that sale to take place it had to come before the Commission, and I would have to assume -- I mean, I wasn't personally involved, but I would have to assume that that information was provided in order to show the benefits of the sale in order to go forward. So I think that would have been addressed at that point in time. And we know that we haven't changed the rates since that went into effect. So in terms of the separation, the benefit is still going forward today.

Q Well, let's talk about that a minute. With respect to the benefit going forward today, wouldn't it be fair to say that retail customers would be a lot better off if they could get the power that is generated by Big Bend 4 in their fuel costs rather than a portion of the purchased power costs, eliminate those purchases and let the retail customers have Big Bend 4, wouldn't they be better off?

A If you were asking me to look at it first with hindsight, then I probably could say that. But the other piece is that I haven't done an analysis, I don't know what the impact would be to base rates. Because what you're saying is you wouldn't have made the separated sale and you would have kept the capacity. Therefore, the retail customers would have had to pay for that entire capacity all of these years. So I can't say with certainty that they would be better off because they would now have the benefit of the fuel.

Q Did you make any current study to see that in either the year 2000, 2001, or the prospective year retail customers are benefitting from the sale to Hardee Power Partners?

A I have not made any analysis of that. And really, I guess I go back to what I said to you originally. It is a separated sale. And, therefore, those costs are not being borne by the ratepayers. So there is a benefit that is there regardless.

Q But you don't know what it is, and you haven't calculated it, and you have presented no evidence in this proceeding as to what it is, have you?

A I'm not sure that I would really need to present evidence on the benefit of the separated sale from the standpoint of it benefitting the ratepayers.

MR. McWHIRTER: I tender the witness.

CHAIRMAN JACOBS: Questions, staff.

CROSS EXAMINATION

BY MR. KEATING:

Q Ms. Jordan, I just have a few questions regarding TECO's forecasts that were used to develop the factors in this docket, the cost-recovery factors.

A Yes.

Q Has TECO updated its energy and demand forecasts used to support its filing in this docket to take into account the economic impacts of the September 11th terrorist attacks?

A We have looked at it on a somewhat high level. We have not updated our forecasts. There is a feeling from a high level perspective that we may not be as impacted at this point. We have put forth that we will continue to look at the actual compared to the budget, and if we see any deviation at that point, go into a further detailed analysis.

Q So is it your testimony that at this point in time, at least from a broad view or a view from up high that there is not going to be, in your opinion, a material impact on the factors?

A Right now basically we just feel that it is a little premature for us to have enough conclusive information to truly do a new forecast that would have any more certainty than what we currently have filed.

Q So you can't say at this point whether TECO expects that any updated forecast would materially affect its 2002 fuel and capacity factors?

A That is correct.

MR. KEATING: Thank you.

CHAIRMAN JACOBS: Commissioners.

COMMISSIONER DEASON: I have a quick question. The unit power sales contract that Mr. McWhirter was referring to, and is indicated with the HPP designation?

THE WITNESS: Yes.

COMMISSIONER DEASON: Hardee Power Partners, that is subject to a contract, correct?

THE WITNESS: That is correct.

COMMISSIONER DEASON: What is the term of that contract?

THE WITNESS: Mr. Brown, Witness Brown would probably be in a better position to answer that.

COMMISSIONER DEASON: That's fine, I will ask him. Thank you.

CHAIRMAN JACOBS: Redirect.

MR. BEASLEY: I have no redirect. I would like to move the admission of Exhibits 1 through 3.

CHAIRMAN JACOBS: Without objection, show Exhibits 1 through 3 are admitted.

(Exhibits 1, 2, and 3 admitted into the record.)

MR. BEASLEY: I would call Mr. Lynn Brown.

CHAIRMAN JACOBS: Thank you. You are excused, Ms. Jordan.

Mr. Beasley, I had a corrected E4 here, is that -- I assume that is a part of the exhibits that we had previously identified?

MR. BEASLEY: Yes, sir.

CHAIRMAN JACOBS: Okay. So, I will show that as --

the corrected E4 as a part of that.

MR. BEASLEY: Thank you.

W. LYNN BROWN

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

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Mr. Brown, would you please state your name, your business address, and your position with Tampa Electric Company?

A W. Lynn Brown, I am Director of Wholesale Marketing, Tampa Electric Company. The business address is 702 North Franklin Street, Tampa 33602.

Q Did you prepare and submit in this proceeding a document entitled prepared direct testimony of W. Lynn Brown?

A Yes, I did.

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

A Yes, they would.

MR. BEASLEY: I would ask that Mr. Brown's 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: And that direct testimony is not accompanied by an exhibit, so I will ask Mr. Brown to proceed with a summary of his testimony.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010001-EI
FILED: 09/20/01

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT 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 "company") as Director, Wholesale Marketing and Sales.

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

A. I received a Bachelor degree in Electrical Engineering from Louisiana State University in 1972 and subsequently joined Tampa Electric. I held various engineering, operations and managerial positions in Energy Delivery from 1973 through 1997. I became Manager of Short Term Wholesale Trading in April 1997 and was promoted to Director, Wholesale Marketing and Sales in August of 1998 where I am responsible for short- and long-term wholesale power purchases and sales.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I testified before this Commission in Docket No. 990001-EI regarding the appropriateness and prudence of various purchased power agreements. I testified in Docket No. 991779-EI regarding the appropriate application of incentives to wholesale power sales by investor-owned electric utilities. In addition, I testified in Docket No. 010283-EI addressing the appropriate regulatory treatment for non-separated wholesale energy sales by investor-owned electric utilities.

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

A. The purpose of my testimony is to provide an overview of the wholesale energy market and a description of Tampa Electric's wholesale energy purchases and sales activities from 1998 through 2001. I describe the key activities Tampa Electric has undertaken in an effort to take advantage of wholesale purchase and sale opportunities for the benefit of its general body of ratepayers. In addition, I describe the benefits Tampa

Electric achieved for its general body of ratepayers through economy purchases and sales activities. I will also provide an overview of the purchased power agreements that Tampa Electric has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery Clauses. My testimony also describes Tampa Electric's purchased power strategy, which mitigates supply-side risk while providing customers with economically priced purchased power. Finally, I address the appropriateness of encouraging utilities to implement wholesale energy hedging strategies to manage risk.

Q. Please describe the wholesale energy market for the period 1998 through 2001.

A. The wholesale energy market has been very active and volatile over the period of 1998 through 2001. Each year, the market is essentially divided into two distinct periods, June through August (summer) and September through May. High prices and volatility have occurred during the summer periods, however, short-term price spikes have also occurred in the spring, winter and fall.

Forwards prices for the summer of 1998 were well below the spot market. Hot weather in the mid-west and northeast caused the short-term market to peak in July. This led to the demise of certain power marketing firms which further exacerbated the problem. Spot market prices increased dramatically.

In 1999, forwards summer period prices were again below spot prices. This was the result of hot weather in the northern states combined with numerous generating unit outages. Again, spot market prices increased dramatically.

Milder weather in the summer of 2000 quieted the eastern U.S. spot markets, which were under the forwards market's prices. California, however, experienced high spot prices due to hot weather and insufficient generation. In 2000, concern was focused on natural gas prices, which began rising in June 2000 and peaked in January 2001. High gas prices affected the entire nation, but were most prevalent in California. These events caused the forwards wholesale energy markets to rise. This rise was especially prevalent during the first five months of 2001. High winter gas prices and a rise in the spring forwards market impacted Tampa Electric because of its planned generation maintenance activities during the period. For example, forwards pricing for April 2001 was $52.00/MWH versus $25.00/MWH for April 2000, as of February of each year.

This year, mild summer weather and a softer than expected gas market caused spot wholesale energy prices to be lower than the forwards market.

Q. Please describe Tampa Electric's wholesale energy purchases and sales activities for the years 1998 through 2001.

A. Tampa Electric generated 89 percent of its customers' total energy needs from 1998 through 2000 and 83 percent for the first eight months of 2001. The remaining 17 percent of customers' 2001 energy needs were provided with purchased power, of which 50 percent was purchased for economical purposes to avoid running more costly generation. As discussed in the direct testimony of Tampa Electric's witness Mark J. Hornick, past and present purchased power volumes have been impacted by several key operational events.

Tampa Electric constantly assesses the wholesale energy market and enters into long-term and short-term purchases based on price and availability of supply. In addition to Hardee and qualifying facility purchases, the company purchased 155 MW of firm capacity for the winter of 2001 and 160 MW for the summer of 2001, which were made at or below current forwards markets prices. Tampa Electric also contracted to lease 39 completely self-contained portable generators to supplement the company's supply through the summer period. The generators supplied up to 70 MW of peaking power to retail customers.

Through August of this year, 53 percent of Tampa Electric's total purchases were from the short-term hourly to monthly market and 47 percent of total purchases were from the long-term market. This purchasing strategy provides a balanced and diversified approach to serving Tampa Electric's customers. From January through August 2001, Tampa Electric paid an average of $57.36/MWH for total energy purchases compared to a forwards energy market price of $86.31/MWH for the same period, indexed to December 2000. Further, Tampa Electric's total purchased power cost in 2001, including capacity payments, is less than the forwards energy market. Tampa Electric has also entered into non-firm non-separated wholesale sales which have provided retail customers $1,356,404 in gains, which are flowed back to customers through the Fuel and Purchased Power Cost Recovery Clause from January through August 2001. The company has not entered into any firm separated or non-separated wholesale sales since 1998.

Q. For the period January 1998 to December 2000, were Tampa Electric's decisions regarding its Hardee Power Partners ("HPP") wholesale energy purchases and sales reasonable?

A. Yes. The HPP cost-based purchases have been very beneficial to Tampa Electric's customers. For example, Hardee generating station availability was 96 percent in 2000 and is over 97 percent through July 2001. This year, HPP's energy price of $53.99/MWH was below the $76.37/MWH forwards market price as of December 2000. Further, even if capacity payments are included, Hardee is less costly than the forwards market.

HPP provided Tampa Electric 295 MW of gas-fired capacity this year under the long-term purchased power agreement that has been in effect since January 1993. This agreement was amended in May 2000 when 82 MW of gas-fired combustion turbine capacity was added. This long-term agreement was presented to this Commission and approved in Docket No. 990001-EI proceedings.

Q. What are Tampa Electric's plans for 2002 regarding capacity and energy purchases?

A. In addition to the HPP and qualifying facility purchases that continue through 2002, Tampa Electric finalized two short-term firm capacity and energy purchases which provide 40 MW for the winter period and 50 MW for the summer period. The company has also committed to purchase 50 MW of distributed generation for the summer period. Tampa Electric is currently in the process of negotiating the purchase of additional capacity and energy for calendar year 2002. Short-term capacity purchases will augment existing long-term purchases and native generation to insure a minimum 15 percent planning reserve margin. A combination of forwards and spot market energy purchases will also be made to cover Tampa Electric's active spring and fall generation maintenance periods and peak period needs.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric aggressively shops for wholesale capacity and energy, searching for reliable supply at the best possible price. These purchases are evaluated based on forwards and spot markets. The company now engages in wholesale power purchases and sales with over 30 counterparties. Each counterparty's creditworthiness is carefully checked before engaging in an enabling agreement. Tampa Electric also subscribes to market publications and services that provide current commodity prices and availability of supply information. Purchases are made to achieve required installed reserve capacity, to meet our customers' needs during planned and unplanned generating unit outages and for economical purposes.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions?

A. Tampa Electric does not purchase or sell wholesale energy derivatives, however, the company's power supply strategy includes self-generation and long-term and short-term capacity and energy purchases. As stated earlier, approximately half of Tampa Electric's 2001 purchased power has been from long-term contracts. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Should physical or financial hedging be used by Florida's investor-owned electric utilities to mitigate wholesale energy price volatility?

A. Physical and financial hedges provide measurable market price volatility protection; however, they come with a price. The price can be quite high in a developing market such as Florida's wholesale energy market.

Q. As the Commission continues to examine hedging practices, what considerations should it take into account?

A. Should the Commission decide to continue pursuing hedging practices, an assessment of the quantitative and qualitative costs and benefits of physical and/or financial hedging should be considered. It should be determined if the benefits of an appropriate hedging strategy outweigh the costs. Providing that benefits outweigh costs, only then should the Commission and the utility commit to an approved hedging strategy, which may be implemented and evaluated on a calendar year basis. In addition, in advance of implementing each utility's strategy, the Commission and utilities must determine the reporting requirements and a methodology for assessing the expected effectiveness of the strategy. Each utility's strategy will be unique to its given current wholesale activities.

Q. Please summarize your testimony.

A. Tampa Electric has utilized its best efforts to take advantage of opportunities in the wholesale electric power market and those efforts have benefited the company's retail customers. The company constantly monitors and assesses the wholesale energy market to take advantage of buying and selling opportunities that offer cost savings to its general body of retail customers. The company's energy supply strategy includes self-generation and long and short-term power purchases. The company has engaged in both forwards and spot wholesale energy markets to provide customers with reliable supply at the lowest possible cost. The company has also made non-firm, non-separated wholesale energy sales which have benefited its customers. Tampa Electric believes that the subject of hedging for wholesale energy transactions should be carefully analyzed before being implemented to ensure that it is appropriate to pursue on a utility specific basis.

Q. Does that conclude your testimony?

A. Yes, it does.

THE WITNESS: Good afternoon, Commissioners. The wholesale electric market has been very volatile in recent years. The late 1990s were known for spot market price spikes, especially during summer months which affected forwards markets for the coming years. In addition, natural gas prices increased from June of 2000 through January of 2001, which impacted spot and forwards electricity markets. These market movements have caused Tampa Electric to adopt a balanced purchased power strategy. While 83 percent of Tampa Electric's retail customers' 2001 capacity and energy needs have been supplied from Tampa Electric generation, the remaining 17 percent was obtained from long and short-term wholesale purchases.

This year seasonal firm capacity and energy purchases helped Tampa Electric achieve a 15 percent minimum reserve. Additionally, the company has taken advantage of favorable pricing by purchasing economy energy when it is less costly than running more expensive generating units. The long-term purchase of capacity and energy from Hardee Power Station continues to be beneficial to retail customers. Hardee's Generating Station availability has been 97 percent this year. Hardee provides cost-based intermediate and peaking power to Tampa Electric's retail customers. Overall wholesale energy purchases this year have been about evenly split between long and short-term markets. Because of this balanced purchased power strategy, Tampa Electric has taken advantage of favorable spot market pricing while maintaining reliable service to its customers.

For 2002, Tampa Electric has purchased firm capacity and energy totalling 40 megawatts for the winter and 50 megawatts for the summer. The company also continues to aggressively shop the long and short-term markets for the best possible products at the lowest possible prices.

This concludes my summary.

MR. BEASLEY: We tender Mr. Brown for questions.

MR. VANDIVER: No questions.

MR. CLOUD: No questions.

CHAIRMAN JACOBS: Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Brown, you said that 82 percent of your retail requirements are met by your own generation?

A I believe I said 83 percent.

Q 83 percent. And for that part you pay $392 million a year, the remaining percentage is met by your wholesale sales. And according to the exhibit that -- Exhibit 3, Schedule E1, you pay $143 million for your wholesale purchases. And although they only represent 18 percent of your electricity use, they represent nearly 30 percent of the cost of the electricity passed along to retail customers, isn't that right?

A Mr. McWhirter, I am not familiar with the E Schedules, and the numbers that you have quoted, I would have to ask for help in verifying that those numbers are indeed correct.

Q Well, would you accept it subject to check and then tell us if that is --

A No, I can't accept that.

Q All right. Have you got a copy of Ms. Jordan's testimony?

A No, I do not.

Q All right. Would you hand him a copy of Ms. Jordan's testimony.

(Pause).

MR. BEASLEY: Mr. Chairman, I think Ms. Jordan is the appropriate person to ask. And the same with Mr. Brown, he didn't prepare that testimony.

MR. McWHIRTER: Well, that is --

CHAIRMAN JACOBS: I will allow him to at least review the schedule and if he at that time maintains that he has no knowledge, we will proceed from there.

MR. McWHIRTER: All I'm asking is that he give us the percentage of costs. He has given us the percentage of sales, but he hasn't given us the percentage of costs of the purchased power sales. That seems like it would a rational thing to do.

BY MR. McWHIRTER:

Q Can you figure that out from Ms. Jordan's exhibit?
A Well, as I said before, I'm not altogether that familiar with the E Schedules, but I will do the best I can. Now, as you said before, you were referring to which line?
Q Look at Line 5, and that shows you the --
COMMISSIONER DEASON: Mr. McWhirter, can you direct us to what you are looking at so we can find it.
MR. McWHIRTER: Yes. I'm looking at Page 24 of Ms. Jordan's Exhibit 3. It is Schedule E1.
COMMISSIONER DEASON: Thank you.
BY MR. McWHIRTER:
Q Look at the cents per kilowatt hour. For your generated power you paid $23.12 a megawatt hour, is that correct, according to her schedule?
A Yes, sir. That is Line 5.
Q And for the purchased power that -- on the purchases you paid $52.62 a megawatt hour.
A I don't see that number.
Q Look on Line 6, the last column.
A Okay. I see that. Line 6, 52.63.
Q Now, although 80 percent of the megawatt -- 83 percent of the megawatt hours went to retail customers, what percent of the cost of those megawatt hours did the retail customers pay?
A Well, I'm not sure you can really compare it, because

if I read this correctly, this is Schedule E1, which summarizes fuel cost and does not have capacity cost included in it. The capacity cost of Tampa Electric owned generation is pretty significant. And by not including that in the cost of generating power, I'm not sure it really is an apples-to-apples comparison.

The cost of purchased power, the 52.63 that you referred to, often includes capacity. In other words, when you buy power on the wholesale market and pay for it on a per megawatt hour basis, it includes a capacity component. And so I just don't see you comparing apples-to-apples with these figures. You would have to go back and include the cost, I would think, of capacity of native generation.

Q With respect to your purchases from Hardee Power Partners, you filed a late-filed exhibit to your deposition in which you included both the capacity payment and the energy payment, is that correct?

A Yes, I do.

Q And those combined purchases were $74.17 a megawatt hour?

A Yes. Approximately that, as I recall.

Q Now, when you sell to Hardee Power Partners, are there any charges that flow back to the retail consumers from those sales or are they restricted to the $25.62 that you receive from Hardee Power Partners?

A Well, the energy component of that sale includes fuel which, I believe, is the charge that you just described. It also includes an O&M piece, which is incremental O&M of making that sale. And the two added together make up the energy charge.

Q I see. And does the O&M money you receive go to the retail consumers or does it go above-the-line to Tampa Electric?

A I believe it is just simply passed back as an operating expense, credited to the operating expenses of the company.

Q But am I missing something, when it looks to me like when you buy power from your affiliated company, you pay $25.62 for it? I mean, you pay, $74.17 for it, and when you sell to your affiliated company, you sell it for $25.56 plus the O&M charge that Tampa Electric keeps?

A In the sell case you are looking at the energy charge. In the purchase case, and in response to that interrogatory in the purchased case I added the capacity and the energy together to come up with that $74 number. As I recall, the energy piece was something less than that. It was approximately $52, approximately. Something in that neighborhood.

Q That is correct. The energy piece is 53.99 and the capacity payment is $20.18. Does that refresh your recollection?

A That is approximately right, yes.

Q But when you buy power from your affiliated company, that's what you pay and pass along to your customers. When you sell power to your affiliated company, Hardee Power Partners, how much is credited to the retail customers' fuel costs, is it the $25.62?

A Yes, whatever the fuel actually costs.

Q Is there any additional money that the retail customers receive?

A Not to my knowledge.

Q Ms. Jordan referred this to you. Have you done a current analysis to determine that the retail customers are still benefitting from the Hardee Power transaction?

A No, I have not.

Q Do you know of anyone in this case that has presented that evidence?

A Not to my knowledge.

Q All right. Now, you were asked in your deposition to furnish information with respect to your wholesale sales, and the sale to TECO Power Services of Big Bend 4, that is the same as Hardee Power Partners?

A Yes.

Q And that sale in this exhibit you show runs until December 31st, 2002?

A Yes.
Q Now, when the Florida Reliability Coordinating Council determined what Tampa Electric's reserve margins were, it found that that contract lasted until the year 2013. Which is it, 2002 it will expire, or 2013?
A The sale that we are referring to, which is the 145 megawatts --
Q Yes.
A -- expires in 2002, December 31st.
Q Are you presently negotiating to renew that contract?
A No. I think perhaps the other sale, or the other date that you mentioned, 2013, that probably relates to the Hardee Power Station sale to Seminole. That contract expires the end of 2012.
Q I see. So the two numbers are not consistent?
A They are not the same. They are not -- the expiration is different on those two transactions.
Q Well, in determining your reserve margin, does the 140 megawatts of Big Bend come back to Tampa Electric as a generating asset in 2002, or does it come back in 2013?
A It actually comes back at the end of 2002, yes, sir.
Q All right. And would you explain, again, what the 2013 number is?
A The Hardee Power Station transaction between Tampa Electric, Seminole, and Hardee Power Partners is a 20-year

agreement that began in January, on January 1 of 1993. It extends for 20 years through, of course, 2012. That is the -- and that is the Hardee Power Station sale to Tampa Electric and Seminole, which originally was 295 megawatts of intermediate and peaking capacity, and since has been modified. In fact, two years ago we modified that agreement with two amendments to add another CT of 82 megawatts. That is the agreement, that is the sale that I am referring to that goes through 2012.

Q That goes to Seminole and not to Tampa Electric?

A It goes to both entities.

Q On the Seminole Schedule D sale that was entered into in 1991, that runs until 2002, but then you have got a footnote that says that contract termination can be as early as June 1, 2002 with three years written notice. To date written notice has not been received. So does that mean that that Schedule D sale is what I would call a -- what do you call that, evergreen contract unless there is a three-year notice?

A That is correct.

Q Do you have any right to terminate that contract?

A Not to my knowledge.

Q And under that contract, is that a separated sale or a nonseparated sale?

A That sale is nonseparated.

Q And that sale, Seminole has the right to your power, but the retail customers pay for the capacity?

A Well, let me make sure we are on the same page here. The Seminole D sale, the sale you're describing that terminates once three-year notice has been given, is the sale that Witness Jordan referred to earlier. It is a sale to Seminole, who in turn resells the capacity and energy to Peace River Electric Cooperative, who in turn serves interruptible customers, retail customers of Tampa Electric's who are located in Peace River's territory.

Another piece of that sale is the sale from Tampa Electric to Seminole. Seminole then serves Peace River Electric Co-op, who serves the station's service of Hardee Power Station. In other words, serves the power that is needed by the station to function. So those are the customers, the two customers, if you will, of that Seminole D sale. They are retail customers. They are both nonfirm customers. And it is a nonseparated sale.

Q And with respect to the sale to the Hardee Station from Tampa Electric Company, how is that sale priced?

A It is priced based on the interruptible service tariff. I believe it is the IS-1 rate.

Q So when you sell it to your affiliated company, you sell it at an interruptible price?

A Because it is interruptible service.

Q I see. And so that is just like a retail sale, then?

A Yes, that is wheeled through Seminole.

Q And the money from that, then would flow -- because it is a Schedule E sale, that money would flow through the fuel clause to the benefit of the retail customers, wouldn't it?

A Yes, because it is a nonseparated sale.

Q And my recollection is that the current charge to interruptible customers is substantially more than $14 a megawatt hour, and that is what Ms. Jordan's schedule showed the revenue to be. Can you explain where the rest of that money goes?

A Well, I do know that the Hardee Station service is normally taken at night whenever the power station is not operating, that is when the station's service is taken. Whenever the power station is operating, then they supply their own. So it's only a night take or an off-peak take, and I suspect that is probably the reason.

Q Is that served on the IS-1 time-of-day schedule or some kind of realtime pricing schedule?

A I'm not sure.

Q I see. And when you buy premium power that you pass along to the retail IS-1 customers, does that retail -- that premium power pass along to the Hardee Power Station under the contract?

A Are you referring to optional provision?

Q Yes.

A Okay. I'm going to make an assumption that it does.

I don't know for sure. That would be an appropriate question for Ms. Jordan. But since they are an interruptible service retail customer, I would assume that they would pay their fair share.

Q So it's a wholesale customer that is priced on a retail rate?

A That is correct.

Q Now, with respect to these wholesale sales, are the prices in those contracts set by this Commission, or by some other regulatory body, or no regulatory body?

A Well, the sale to Hardee Power Station is a -- since they are a retail customer --

Q We're talking about the Schedule D now, not the --

A The Schedule D, yes. Is that what we are talking about?

Q I am referring in general to your wholesale sales. Who sets the price or regulates that price?

A The long-term wholesale sales that we have in place -- and most, by the way, of the wholesale sales that we have in place, if not all, have been in place for many, many years. We have not entered into any new long-term wholesale sales in the past several years. So all of our sales are cost-based, not market-based. They are cost-based wholesale sales. Because at the time all we had was cost-based rate authority from the FERC.

Now, since 1999, I believe it is, we have obtained market-based rate pricing authority. However, since we have obtained that authority we have not engaged in any long-term or any firm wholesale sales.

Q When you say cost-based, is that cost as defined by FERC or cost as defined by your last rate case in this proceeding?

A Cost as defined by FERC.

Q Is that exactly the same as cost determined by this Commission?

A That is a question I'm not sure I know the answer to. The last rate case or justification, if you will, that we provided FERC was for our requirements tariff, and that was back in the early '90s. And if we had had a state rate case at the same exact time, then I would say that those numbers would be the same, however, I don't believe we did.

Q On your sales to Fort Meade, St. Cloud, and Wauchula, they were entered into in 1993 and then renewed in 1997 according to your late-filed exhibit to your deposition?

A Which exhibit are you referring to?

Q I am referring to Page 2 of 4. Well, I guess it is in response to staff's second set of interrogatories Number 4 to you. Let me give you this and see if it refreshes your recollection.

A The contracts with Fort Meade, St. Cloud, and

Wauchula were entered into in 1993. The sale did not actually begin until 1997.

Q Were you building something in order to accommodate those sales at the time?

A Not to my knowledge.

Q Did you have a prior contract with those entities that provided power that this '93 contract superseded?

A Yes, we did.

Q You did?

A Yes. By the way, the total megawatts of all three of those added together was less than 50 megawatts. It was approximately 40 megawatts.

Q And you charged those people system average fuel cost?

A Yes.

Q And do you charge them any capacity costs?

A Yes.

Q You do?

A Yes, we do.

Q And that capacity cost goes to Tampa Electric Company and not to its customers?

A How that is actually handled, I'm not totally sure, but my understanding is these three customers, these three contracts are treated in the same way as retail customers are. So however the capacity revenues are treated there would -- my understanding is it is the same treatment. They are under our AR-1 tariff.

Q I see. When you say they were entered into in '93, they were maybe part of that '93 rate order and were separated out in '93, is that what the deal is?

A I don't think that that was part of the rate order. I believe these were individual customers who we entered into an all requirements or a partial requirements contract or service with to provide their needs.

Q And the price for that was set by -- that wholesale sale was set by this Commission or by FERC?

A By FERC.

Q And it would be different than the price set by this Commission unless the two rate cases were contemporaneous?

A Yes, they were cost-based. In other words, the capacity component is the same as the retail customers' capacity component. The fuel component is as you said, system average fuel, which is the same as the retail customers' fuel component. And these sales also in their fuel component include all purchased power, their applicable share of purchased power.

Q How about your Reedy Creek Improvement District sale, that runs until 2017?

A Yes.

Q Is that a unit specific contract or is it just from your general units?

A That sale is very similar to the three previous that we described. It is a system sale.

Q And how many megawatts are involved in that sale?

A Up to 75.

Q 75. And if your retail customers need the capacity, they cannot, you cannot interrupt Reedy Creek in order to give them that capacity?

A No.

Q Was any analysis done to your knowledge by this Commission in 1995 concerning the benefits that retail customers would receive from that sale?

A Not to my knowledge, although I was not in this part of the company in 1995, so it may have happened, I don't know.

CHAIRMAN JACOBS: Mr. McWhirter, is it time to break Is this a good point?

MR. McWHIRTER: I am about to wind up, Mr. Chairman.

CHAIRMAN JACOBS: Okay.

MR. McWHIRTER: Well, I will tender the witness and let you --

CHAIRMAN JACOBS: No, no, I don't want to make you finish prematurely, by all means. But if you are done, we will take a break for ten minutes and come back.

MR. McWHIRTER: This is a good breaking point. I will tender the witness.

CHAIRMAN JACOBS: We will be back in ten minutes.

(Recess.)

CHAIRMAN JACOBS: We will go back on the record. Mr. McWhirter, you were completed? Staff.

MR. KEATING: Staff is going to hand out a composite exhibit that consists of various items. There are some deposition transcripts and discovery related to TECO's witnesses. As they hand this out, there is a few items -- the cover sheet lists the items included in the composite exhibit and there is a few items on that list that I'm going to delete, that we will not ask to have included as part of the exhibit. But since the copies were made already, they are in the packet. Staff is also handing out --

CHAIRMAN JACOBS: Should we mark this?

MR. KEATING: If you can mark the composite exhibit, I guess the next available number is 4.

CHAIRMAN JACOBS: Correct.

MR. KEATING: The staff has also handed out a confidential exhibit in the red folder, and that contains the confidential responses to Interrogatories 5 and 6 and 149 and 150. The redacted responses are included in what has been identified as Exhibit 4. If we could have that confidential exhibit marked as Exhibit 5.

(Exhibit 4 and Confidential Exhibit 5 marked for identification.)

CROSS EXAMINATION

BY MR. KEATING:

Q Good afternoon, Mr. Brown. I just have a few questions for you. When was the last time that TECO entered into a long-term separated sale?

A It was back in, I believe, 1996.

Q Was that the sale with the Reedy Creek Improvement District?

A No, that was the sale to FMPA that I'm thinking of.

Q To FMPA?

A Yes.

Q Has TECO entered into any other long-term separated sales since that time?

A Not to my knowledge. The Reedy Creek sale, I think, as was referred to earlier, started in '97. Excuse me, the sale actually began in '98, but the sale was entered into back in 1995. So the entered into date was really the date that I was referring to.

Q At the time that TECO entered into each of its current long-term separated sales commitments, those are the separated sales that it is currently serving, were TECO's planning reserve margins over 15 percent?

A Yes, they were.

Q Are all of TECO's current long-term sales agreements cost-based?

A Yes, they are, all of them.
Q According to your response to the staff interrogatory which is Interrogatory Number 4, I don't believe you need to turn to that specifically, but if you could just confirm that the only long-term sales agreement that can be recalled to serve firm retail load is the Schedule D sale with Seminole, is that correct?
A Of the current sales that we have going?
Q Yes.
A Yes.
Q Has this sale been recalled to serve firm load?
A Yes.
Q When was the last time that TECO agreed to any type of firm sale transaction?
A We agreed to a nonseparated firm sale for a short period of time in 1998. That was the last time, and the sale was less than one year.
Q You say that was a nonseparated sale?
A Yes, it was.
Q At the time that TECO entered into that sale, did it expect to have at least 15 percent reserve margin for the duration of the sale?
A Yes.
Q Is TECO currently negotiating any new firm long-term or nonseparated sales agreements?

A Yes, we are.

Q When are those planned to begin?

A Those sales that we are discussing relate to the addition of Bayside, the Bayside plant to our fleet, and those discussions began earlier this year.

Q So those sales would not begin until after completion of the Bayside units?

A That is correct.

Q And do you know when the Bayside units are expected to be ready for service?

A Yes, June of '03.

Q Let me ask you about the TECO contract with Hardee Power Partners. In your testimony you state that Hardee's energy price compares favorably to the December 2000 forwards market price, is that correct?

A Yes.

Q Could you explain how you made that comparison?

A I looked at the energy costs that we have paid Hardee Power Partners for the period January through July of this year, and I compared it to the forwards market for the Entergy hub, which was published in December of 2000 for the period January through July of 2001. I compared the two and found that the energy costs that we had paid Hardee, that is the all in energy cost, was less.

Q Is the Hardee price lower than the forwards price, even including capacity costs?

A Yes.

Q Is it your understanding that the forwards market price only goes out for 12 months?

A That is true, that is the published market. It is an energy market.

Q Did TECO compare the Hardee contract to the forwards market price at the time that it was signed?

A At the time it was signed there was no forwards published market.

Q At the time that the most recent amendment to the Hardee contract was signed, did TECO compare the contract to the forwards market price?

A No, we did not.

Q Do you believe that relying on the short-term market rather than TECO owning its own capacity exposes customers to risk due to the price volatility of the wholesale market?

A If you take a conservative approach and serve 100 percent of your load out of native generation, then the cost may actually be more than purchasing some energy on the short-term market. It depends on the market, really. We do take advantage of the short-term market, particularly for economy purchases in lieu of running our own generation. We purchase for cheaper prices on the short-term market.

Q Would you agree that the short-term market is going to be more volatile?

A Oh, yes, absolutely.

Q Staff's Interrogatory Number 5 that is included in the packet discusses circumstances surrounding interruptions of nonfirm retail customers during the period 1998 to 2001. And if you need to look at that interrogatory, let me know, but the question is was TECO making any recallable sales during these interruptions?

A Could you speak up, I'm having trouble hearing you.

Q Yes. Was TECO making any recallable sales during the interruptions that are listed in its response to Interrogatory Number 5?

A No.

Q And, Mr. Brown, did you prepare Tampa Electric's responses to staff's Interrogatories 2, 3, 4, 5, 6, and 8 as they are listed in the exhibit?

A Yes. I was either responsible for them or I worked with others in preparing them, yes.

Q And would you agree that those responses are still accurate at this point in time?

A Yes.

Q And with respect to Interrogatory Numbers 149, 150, 155, 156, and 157, which are included in the staff exhibit, did you prepare the responses to those interrogatories?

A Yes. I either prepared them or I worked with others to prepare them, yes.

Q And can you confirm that those responses are still accurate?

A Yes.

MR. KEATING: Staff has no other questions.

CHAIRMAN JACOBS: Commissioners.

COMMISSIONER DEASON: Well, I had my question that was handed off to you, and I think you have answered it earlier in that the contract expires at the end of 2002 for the Hardee Power Partners.

THE WITNESS: That is correct. The 145-megawatt Big Bend 4 sale?

COMMISSIONER DEASON: Yes.

THE WITNESS: Yes, it does.

COMMISSIONER DEASON: Okay. When that contract expires, assuming there is no renewal of that contract, what happens to that capacity?

THE WITNESS: It would go back into rate base, I assume.

COMMISSIONER DEASON: So it would no longer be separated, it would become part of retail rate base?

THE WITNESS: That is correct.

COMMISSIONER DEASON: Do you know what the company's plans are -- I don't want you to divulge any confidential information, but do you know what the company's plans are in relation to that capacity?

THE WITNESS: At this point I believe our plans are for it to come back into rate base.

COMMISSIONER DEASON: All right. Thank you.

CHAIRMAN JACOBS: Any other questions, Commissioners?

Just one moment, I think I have a question on the interrogatory. Do you have the response to Interrogatories 5 and 6 in front of you, Mr. Brown?

THE WITNESS: Yes.

CHAIRMAN JACOBS: I want to make sure I understand. Without divulging any of the confidential information, just make sure I understand this. The tables in 5, those are, in essence, contracts under which you purchase or sell?

THE WITNESS: These tables are contracts that we sell. The identification of the purchasing party --

CHAIRMAN JACOBS: Is at the top?

THE WITNESS: Is at the top, yes, sir.

CHAIRMAN JACOBS: Okay. And then I understand it better. Okay. That's all of my questions.

Redirect, Mr. Beasley.

MR. BEASLEY: No redirect.

CHAIRMAN JACOBS: Exhibits.

MR. BEASLEY: No exhibits to move.

CHAIRMAN JACOBS: That's right. It was staff, your exhibits.

MR. KEATING: Staff would move 4 and 5.

MS. KAUFMAN: Chairman Jacobs, I had a question, and then I might have an objection to part of staff's exhibit. And my question is Exhibit Number 5 is intended to be the confidential sections of what is redacted from Exhibit Number 4, is that correct? I just wanted to be clear.

CHAIRMAN JACOBS: Actually, yes, yes. I assume there was some part of -- Exhibit 4 is more than just 5, but there was some part of --

MR. KEATING: That is correct. Exhibit 5 contains the confidential information included as part of -- that was part of the response to Interrogatories 5 and 6 and 149 and 150.

MS. KAUFMAN: Thank you for that clarification. FIPUG would object, however, to the depositions of Mr. Brown, Ms. Jordon, and Mr. Hornick coming into the record, as well as the prepared direct and rebuttal testimony of Mr. Brown from a prior proceeding. As to the depositions, I believe these witnesses were here, they were available for cross-examination. And as to Mr. Brown's testimony from -- I guess we are talking three years ago, I think it is inappropriate to put prefiled direct testimony into the record. If that was important testimony, Mr. Brown should have sponsored it and stood for cross-examination in regard to it.

MR. KEATING: If I could address each one of those.

And I apologize, I may have gone through those too quickly when we handed out the exhibit. Staff does not wish to include -- if we look at the cover sheet on the exhibit, the third numbered item, which is the prepared direct and rebuttal testimony of W. Lynn Brown. It had already been copied and made a part of this packet. We have gone back and asked that that not be included as part of what is moved in.

MS. KAUFMAN: I'm sorry, Mr. Keating, I didn't realize that.

MR. KEATING: And we also would strike 6 and 7.

CHAIRMAN JACOBS: So we are striking what you list as Item 3 here, striking 6 and 7?

MR. KEATING: Correct. And with respect to Mr. Hornick's deposition, we have offered that, or we ask that that be moved into the record solely for support on stipulated Issues 24A and 24B which relate to TECO's generating performance incentive factor. Mr. Hornick was excused, and that was -- we don't have him here to answer those questions at this time.

MS. KAUFMAN: Mr. Keating or Chairman, I haven't had an opportunity to read Mr. Hornick's deposition. Are you saying that his deposition relates only to GPIF, it doesn't address any other issues that he was responsible for?

MR. KEATING: I believe it primarily relates to GPIF. We are offering it solely in relation to the GPIF issues.

CHAIRMAN JACOBS: I am going to allow you to review that transcript and leave your objection pending.

MS. KAUFMAN: That would be fine. And I think we also object to Mr. Brown's deposition, as well.

MR. KEATING: And staff has offered this solely for the purposes of trying to streamline the hearing and not go through the line of questioning again that we did with Mr. Brown in deposition. I believe the transcript includes the parties' cross-examination and redirect at that deposition.

CHAIRMAN JACOBS: Is it the deposition in total or a particular portion?

MS. KAUFMAN: Well, Mr. Chairman, I object to use of the deposition, yes, in total. Mr. Brown was here, all the parties have the opportunity to cross-examine him in regard to his prefiled testimony to the extent that they wish to, so I think it is an inappropriate use of his deposition.

CHAIRMAN JACOBS: Okay. Traditionally we have given liberal construction to the deposition rule in many instances particularly with regard to staff. It is a balancing test in my mind. I am not persuaded that there is any particular harm done in this instance by allowing the deposition transcript in, and so I will deny the objection. So then show the exhibit marked as Exhibit 5 will include the transcript, deposition transcript of Mr. Brown dated October 25th, 2001, late-filed exhibits to that deposition, TECO's responses to staff's second set of interrogatories, TECO's responses to staff's fourth set of interrogatories, and the transcript of Mr. Hornick's deposition subject to review by Ms. Kaufman. Any questions? Very well. And noting that objection, Exhibits 4 and 5 are admitted. Thank you.

(Exhibits 4 and 5 admitted into the record.)

MR. KEATING: And we will come around and pick up the confidential folders.

(The transcript continues in sequence with Volume 2.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, 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' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 3RD DAY OF DECEMBER, 2001.

JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
FPSC Division of Commission Clerk and
Administrative Services
(850) 413-6732