BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : DOCKET NO. 970001-EI

Fuel and purchased power cost recovery clause and generating performance incentive factor.

VOLUME 2

Pages 173 through 291

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN JULIA L. JOHNSON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER JOE GARCIA

DATE: Thursday, August 14, 1997

TIME: Commenced at 9:30 a.m.

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

REPORTED BY: JOY KELLY CSR, RPR
Chief, Bureau of Reporting
H. RUTHE POTAMI, CSR, RPR
Official Commission Reporters

APPEARANCES:

(As heretofore noted.)

WITNESSES

EXHIBITS

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

CHAIRMAN JOHNSON: I think we're to Gulf Power's witness. Is it Mr. Howell?

MR. STONE: That is correct. For the record, Mr. Howell was present earlier when the witnesses were sworn.

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M. W. HOWELL

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

DIRECT EXAMINATION

BY MR. STONE:

Q Would you please state your name for the record?

A Name is M. W. Howell.

Q And are you the same M. W. Howell who prefiled direct testimony dated June 23, 1997?

A Yes.

Q Do you have any changes or corrections to that prefiled direct testimony consisting of 17 pages?

A No.

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

A Yes.

MR. STONE: Chairman Johnson --

CHAIRMAN JOHNSON: I'm sorry. You said 17 pages?

MR. STONE: I am referring to his prefiled direct testimony dated June 23. There was an earlier set of testimony, a true-up testimony, that has previously been stipulated into the record that may have a different page count.

CHAIRMAN JOHNSON: You're right. I think they probably forwarded me the wrong copy. Staff, do you have a extra copy of Mr. Howell's?

MS. PAUGH: Of his testimony?

CHAIRMAN JOHNSON: Yes.

MS. PAUGH: I don't.

CHAIRMAN JOHNSON: Go ahead. 1 through 17.

COMMISSIONER GARCIA: That's including the exhibits, right?

MR. STONE: I hadn't gotten to the exhibits, but there are exhibits attached to the back of June 23, yes.

WITNESS HOWELL: We've got, I think, an extra copy if all three of the Commissioners do not have a copy at this time.

CHAIRMAN JOHNSON: I'm probably the only one.

WITNESS HOWELL: Hold on for just a second. (Pause)

CHAIRMAN JOHNSON: Now, did you say there were going to be some corrections?

MR. STONE: We ascertained that there were no corrections. I believe that's correct, isn't it, Mr. Howell?

WITNESS HOWELL: There are no corrections; that is correct.

CHAIRMAN JOHNSON: Okay.

MR. STONE: For the sake of clarity, I would ask that his entire testimony be inserted into the record as though read; but for purposes of these issues we're focusing on that portion of his testimony that begins at Page 12 at Line 17 and continues through the end of his testimony on Page 17.

CHAIRMAN JOHNSON: Okay.

Q (By Mr. Stone) Mr. Howell, you also have an exhibit that's referred to in that portion of your testimony that was identified MWH-2; is that correct?

A Yes.

MR. STONE: May we have that exhibit identified for the record?

CHAIRMAN JOHNSON: I have an MWH-1 and an MWH-2.

MR. STONE: Your preference. MWH-1 refers to the stipulated issues, and you had not given numbers to those yet, so MWH-2 is the part that he'll be referring to in this --

CHAIRMAN JOHNSON: Okay. We'll identify MWH-2 as Exhibit 8.

(Exhibit 8 marked for identification.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 970001-EI
Date of Filing: June 23, 1997

Q. Please state your name, business address and occupation.
A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?
A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.
A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission,

Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution system additions; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

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

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to support Gulf Power Company's projection of purchased power recoverable costs for energy purchases and sales for the period October, 1997 - March, 1998. I will also support the Company's projection of purchased power capacity costs for the October, 1997 - September, 1998 annual recovery period. Finally, in response to economy energy pricing and cost recovery issues raised by the Florida Public Service Commission's Staff, I will discuss the changes to the Southern electric system's pricing of economy energy as related to the Federal Energy Regulatory Commission's (FERC) Orders 888 and 888-A.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have two exhibits to which I will refer. These exhibits were prepared under my supervision and direction.

Counsel: We ask that Mr. Howell's exhibits MWH-1 and MWH-2 be marked for identification as Exhibit_____(MWH-1) and Exhibit_8_(MWH-2).

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the October, 1997 - March, 1998 recovery period?

A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $6,609,297. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system power pool. This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the October, 1997 - March, 1998 recovery period?

A. The projected fuel cost for energy sales, shown on line 18 of Schedule E-1, is $13,588,600. These sales also result from Gulf's participation in the coordinated operation of the Southern electric system power pool.

This amount is used by Gulf's witness Susan Cranmer as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. Has Southern made any changes to the Intercompany Interchange Contract (IIC) that was used in the most recent recovery factor adjustment proceedings?

A. Yes. The Southern electric system has filed Amendment No. 8 and Amendment No. 9 to the IIC. These amendments, filed with the FERC on March 5, 1997 and June 6, 1997, respectively, will enhance the system's energy and capacity pricing and enable the system to more readily compete in a market-based environment.

Q. Will these amendments have any effect on Gulf's customer's rates?

A. Yes. Both amendments will reduce the rates that our customers pay.

Q. What are the key features of the two new IIC amendments as related to energy?

A. For a number of years, the Southern electric system has dispatched its generating units using marginal replacement fuel costs, but the pricing of energy was based on blended (long-term contracts plus spot fuel) costs. IIC Amendment No. 8 and Amendment No. 9 will not change the way system units are dispatched, but will affect how energy from the units is priced.

Amendment No. 8, accepted by the FERC on May 2, 1997, has changed the Southern electric system's non-associated pool interchange energy pricing for opportunity (economy) sales. Prior to Amendment No. 8, when Southern made an economy sale to an off-system, non-associated company, the system operating company that supplied more energy than its load ratio obligation in a given hour sold the excess energy to the pool at a rate based on blended replacement fuel costs. Amendment No. 8 changed this rate to one based on marginal replacement fuel costs. However, all other energy pricing, including pool interchange and all Unit Power transactions, will continue to use blended replacement fuel costs.

Under Amendment No. 9, when each operating company supplies pool energy for purchase by the other operating companies to serve their territorial load requirements, it will be based upon marginal pricing.

Q. Will either Amendment affect Gulf's pool capacity transactions?

A. Yes. Amendment No. 9 will also modify the IIC's capacity pricing of shared reserves by incorporating the use of monthly capacity worth factors in the monthly capacity rate calculation. These factors, derived primarily from system reliability studies, are used to allocate annual capacity costs over those months when capacity is most valuable to the customers of the operating companies.

Q. Has Gulf incorporated these new amendments into its projections of energy transactions for the October, 1997-March, 1998 recovery period that is being submitted for approval by the Commission in this proceeding?

A. Yes. Because IIC Amendment No. 8 has been accepted for filing by the FERC, Gulf has incorporated its pricing provision into its energy cost projections. Amendment No. 9 has been incorporated into Gulf's energy cost projections beginning January 1, 1998 to coincide with our requested effective filing date for the amendment. If final FERC acceptance of Amendment No. 9 is delayed, and the Southern electric system decides to base its actual monthly IIC territorial energy billing transactions upon the current blended replacement fuel costs, Gulf will reflect the resulting differences in the true-up filing for the period.

Q. Has Gulf incorporated Amendment No. 9's capacity related modification into its projections of IIC capacity transactions for the October, 1997 - September, 1998 recovery period that is being submitted for approval by the Commission in this proceeding?

A. Yes. Beginning January 1, 1998, the amendment's new capacity pricing has been incorporated into Gulf's capacity cost projections. If final FERC acceptance of Amendment No. 9 is delayed and we decide to base monthly IIC capacity billing transactions upon the current IIC, Gulf will reflect the resulting differences in the true-up filing for the period.

Q. Which power contracts produce capacity transactions that are recovered through Gulf's purchased power capacity cost recovery factors?

A. The two primary power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity recovery factors are the Southern electric system's Intercompany Interchange Contract and Gulf's cogeneration capacity purchase contract with Monsanto Company. The Commission has authorized the Company to include capacity transactions under IIC for recovery through the purchased power capacity cost recovery factors. Gulf will continue to have IIC capacity transactions during the October, 1997 - September, 1998 recovery period. The energy transactions under this contract for these periods are handled for cost recovery purposes through the fuel cost recovery factors.

The Gulf Power/Monsanto cogeneration capacity contract enables Gulf to purchase 19 megawatts of firm capacity from June 1, 1996 until June 1, 2005. Gulf has included these costs for recovery during the October, 1997 - September, 1998 recovery period. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are handled for cost recovery purposes through the fuel cost recovery factors.

Q. Are there any other arrangements that produce capacity transactions that are recovered through Gulf's purchased power capacity cost recovery factors?

A. Yes. Gulf and other Southern electric system operating companies have purchased short-term market capacity for the summer of 1998. Gulf also expects to make additional market purchases of capacity for the summer of 1998, but it is not known at this time what these might be. Any actual costs incurred but not projected will be included in a future true-up filing.

Q. Besides Amendment No. 9 which you discussed earlier, have there been any other changes to the IIC with regard to capacity transactions since the last recovery factor adjustment proceedings?

A. Yes. On November 1, 1996, in accordance with both the contract and the requirements of the FERC, the Southern electric system made its annual IIC informational filing with the FERC. The informational filing reflects updated historical load responsibility ratios, expected system load, and the capacity resource amounts for the 1997 budget cycle that are used in the IIC capacity equalization calculation to determine the capacity transactions and costs for each operating company. All of these changes are reflected in the projection of capacity transactions among the Southern electric system's operating companies for the October, 1997 -September, 1998 recovery period.

Q. What are Gulf's IIC capacity transactions that are projected for the October, 1997 - September, 1998 recovery period?

A. As shown on my exhibit MWH-1, capacity transactions under the IIC vary during each month of the annual recovery period. IIC capacity purchases in the amount of $2,398,766 are projected for the period. IIC capacity sales during the same period are projected to be $1,591,874. Therefore, the Company's net capacity transactions under the IIC for the period are net purchases amounting to $806,892. This is significantly lower than the net purchases of $10,735,529 which were projected for the period October, 1996 - September, 1997.

Q. What is the cost of Gulf's capacity purchase from Monsanto that is projected for the October, 1997 - September, 1998 recovery period?

A. As shown on my exhibit MWH-1, Gulf is projected to pay $746,424, or $62,202 per month, to Monsanto for firm capacity purchases made pursuant to the Commission approved contract.

Q. What is the cost of Gulf's market capacity purchases that is projected for the October, 1997 - September, 1998 recovery period?

A. As shown on my exhibit MWH-1, Gulf is projected to pay a total of $288,353 for the committed market capacity purchases. Capacity in varying amounts will be purchased during the months of June through September of 1998. The individual suppliers and megawatt amounts are not shown, since this is highly sensitive and confidential information. Public availability of this information would seriously undermine our competitive position and cause our customers increased cost.

Q. What are Gulf's total projected net capacity transactions for the October, 1997- September, 1998 recovery period?

A. As shown on my exhibit MWH-1, the net purchases under the IIC, the Monsanto contract, and the committed market capacity purchases will result in a projected net capacity cost of $1,841,669. This annual figure is used by Ms. Cranmer as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost recovery factors for this twelve month recovery period.

Q. Earlier in your testimony, you indicated that in response to economy energy pricing and cost recovery issues raised by the Commission's Staff, you would discuss the changes to the Southern electric system's pricing of economy energy as related to FERC Orders 888 and 888-A.

A. Yes, my testimony will now address these issues.

Q. What is Gulf's relationship to the other operating companies of the Southern electric system as related to economy energy transactions?

A. Gulf and the other Southern operating companies all participate in consolidated Southern economy energy transactions. Gulf does not make economy sales on its own. When I reference Gulf's transactions in the remainder of my testimony, it is our share of the total Southern sale to which I am referring.

Q. Prior to FERC Order 888, how did Gulf determine the price for economy transactions between directly interconnected utilities and recover the associated costs?

A. Gulf included only its incremental cost of production in determining the price for economy transactions. Gulf's economy transaction price was based on the average of the seller's incremental production cost and the buyer's decremental production cost. When Gulf sold economy energy to others, it credited the fuel portion of the production component of the economy price to its fuel cost for recovery through the Fuel Cost Adjustment Clause. Gulf's mark-up was split 80/20 between the retail customer and the shareholders for recovery purposes in the Fuel Cost Adjustment Clause. When Gulf purchased economy energy from others, it charged the full purchase cost to its fuel cost for recovery through the Fuel Cost Adjustment Clause.

Q. In response to FERC Order 888, how does Gulf now determine the price for economy transaction prices between directly interconnected utilities and costs to be recovered?

A. FERC Order 888 required Gulf to include a transmission cost component in the transaction price for economy sales. Because there was no transmission cost component included in Gulf's economy price before Order 888, Gulf now adds its transmission cost after first calculating the average between its incremental production cost and the buyer's decremental production cost. My exhibit MWH-2 illustrates Gulf's economy pricing before and after FERC Order 888. In the exhibit's example, it is assumed that Gulf's incremental production cost is \$20/mwh, the interconnected utility's decremental cost is \$30/mwh, the transmission rate (after Order 888) is \$3/mwh, and both buyer and seller have comparable regulatory treatment. The fuel clause treatment of economy sales revenues and economy purchase costs before and after FERC Order 888 are also shown on my exhibit MWH-2.

Q. Prior to FERC Order 888, how did Gulf determine the price for economy transactions between non-directly interconnected utilities and recover the associated costs?

A. Transactions between Gulf and a non-directly interconnected utility only occurred in an indirect manner. A utility directly interconnected to Gulf would buy the economy energy from Gulf and then resell it to the utility not directly interconnected to the system. Therefore, economy energy pricing and fuel cost recovery under this scenario were identical to the economy pricing and cost recovery for two directly interconnected utilities.

Q. In response to FERC Order 888, how does Gulf now determine the price for economy transaction prices between non-directly interconnected utilities and costs to be recovered?

A. Gulf would add its transmission after first calculating the production cost component of the economy sale. Then, the third party's transmission cost is added. The sale occurs only if the total transaction price is below the non-directly interconnected utility's decremental cost.

However, Gulf expects most future economy transactions will be under the emerging market-based pricing. Under market-based pricing, Gulf has the flexibility to price economy energy based on the prevailing market price. If the market price covers our incremental production cost, transmission cost, and some minimum mark-up, we will make the sale.

Q. Exhibit MWH-2 shows the transmission component being treated as a base rate item, not a part of the mark-up. What is the reason for this?

A. Originally, Gulf determined the economy mark-up before adding the transmission component, so it would be improper to include it as part of the mark-up. More importantly, however, is that accounting for the transmission component as a part of the mark-up would result in the entire transmission component being credited as an 80/20 split between the customer through the fuel clause and the stockholder. Consequently, none of this revenue would be available to be applied to offset transmission costs. Yet, the FERC requires that all transmission revenue be credited in calculating reductions to the transmission tariff rates. Crediting the transmission component through the 80/20 split, and also crediting the tariff rate calculation would be, in effect, "giving away" the money twice, and would eventually result in our customers paying more in base rates.

Q. What should the Commission do, then, regarding the accounting for the transmission component revenue?

A. The Commission should direct that all such transmission revenue be credited to base rates and should not be included as part of the mark-up to be split 80/20.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 970001-EI

Before me the undersigned authority, personally appeared M. W. Howell, who being first duly sworn, deposes, and says that he is the Transmission and System Control Manager of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

M. W. Howell

M. W. Howell
Transmission and System Control Manager

Sworn to and subscribed before me this 17 day of June, 1997.

Notary Public, State of Florida at Large

Commission No.

My Commission Expires

PAUL H. ROBERTS
"Notary Public-State of FL"
Comm. Exp. Sept. 12, 1998
Comm. No. CC 400548

Q (By Mr. Stone) Mr. Howell, would you please summarize that portion of your testimony that begins on Page 12 at Line 17 and continues --

A Yes. Well, Commissioners, officially, good afternoon.

There are a lot of things that I think it's obvious we disagree on, but I think it should be clear that we all agree on one thing; FERC has caused this trouble in both the economy energy pricing and the cost recovery issues as a result of those two infamous orders they have issued.

I'd like to think of my summary as kind of addressing three issues, and they are separate. One is pricing economy; one is what do you do when you're selling with this revenue; one is what do you do with these costs when you're purchasing. So I'll address price first.

The FERC orders have required utilities to include a distinct transmission cost component in the pricing. We have filed compliance tariffs that reflect the inclusion of the transmission service costs as a charge added to the traditional split-the-savings method. Whether or not this will be proper will be ruled on, hopefully some day, by the FERC.

We do not have approval of these yet as most utilities have theirs languishing in Washington, but we do have a FERC approval for market based tariffs. They specify we can charge a market rate for the energy, and we must add a specified transmission service component.

We expect very soon to do essentially all of our economy business this way. It is our view that the industry is rapidly moving away from cost based type pricing and towards market based pricing on economy energy. In any event, FERC will some day hopefully decide how transactions are to be priced.

The real issue before you today is, if we are selling, how do we treat the revenue. And I maintain that that is the issue. And you have two decisions basically: Should you credit that to base rates, or should you credit it to the fuel clause. FERC has required that nonfirm transmission service revenues be credited to the transmission service user when determining transmission service firm tariff prices.

If you direct utilities to credit transmission service revenues from economy to the fuel clause, that will create a double-dipping against the utility, because we then have to credit the revenues to the customer through the fuel clause. We have to credit those revenues to the transmission service customer. And we're not allowed yet to print money, so we wound up short.

Also, you, as the PSC, have made it clear that we should not pollute the fuel clause with variable O&M expenses, in-plant fuel handling expenses, and a lot of other things that might be associated with fuel that are not fuel items. We surely don't think any of us want to put transmission revenues in there at this point.

As far as when we purchase, I think it's a slam dunk. All the utilities agree, in addition to FERC causing these problems, that when we buy economy it doesn't matter how they determined the price. We have a choice of either generating with our own facilities or buying at some price that has been set by maybe a FERC approved tariff.

And if we can buy economy energy, no matter what the components are, if we can buy that cheaper than we can generate ourselves, that's good for our customers. Everybody wins. If we can't do it, then we go ahead and generate.

Gulf and Southern are very different from the peninsula utilities. We're not a party to the

Florida broker. We do engage in economy transactions. We're moving very strongly towards market based rates. But when we do purchase economy, we think that unless the fuel -- if the entire component, the entire price of the economy is allowed to be recovered, we won't make the transaction.

Just because we have now introduced a transmission component into the price shouldn't change the way we've been doing business all along, and that is whatever the economy costs, you ought to be able to recover that; or like any other business, if you cannot recover your costs, you're not going to purchase.

So I would say we're asking you to do two things: One is, go ahead and allow recovery of the transmission component when we're purchasing, otherwise you're going to shut down the economy market. The other is asking you to credit transmission service revenues to base rates to avoid an unfair double hit against the utility.

That concludes my summary on these issues.

MR. STONE: We tender Mr. Howell for cross-examination.

CHAIRMAN JOHNSON: TECO.

MR. LONG: Madam Chairman, I have no

questions.

MR. McGEE: No questions.

CHAIRMAN JOHNSON: Public counsel?

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Howell, characterize for me please, what kind of sales you're referring to when, as I understand it, you're talking about that which is relevant to Gulf is nonbroker economy sales.

A Okay. We're not a member of the Florida broker, okay. In the past, the economy energy transactions that we have made have been pursuant to FERC approved tariffs, amendments, whatever we want to call them here in legalese, with interconnected and noninterconnected utilities; and they have been cost based type economy transactions.

The new transactions that we will expect to make basically all of our exchanges on the future are what we call market based. A cost based transaction -- now split-the-savings is one form of cost based. You look at your cost, you look at his cost, you look at what other costs there are, and you come up with a price. That's a cost based transaction.

A market based transaction says, what is the market price for this, and as long as we can sell somebody something at a market price they're willing to pay that has all the components in it that FERC requires, then the transaction would take place.

Q With regard to the revenue that's credited for these sales, do I understand your testimony to be that in historical Gulf Power rate cases that those have been credited in the establishment of the base rates?

A They --

Q An estimated portion for projected test year?

A Yes. They have always been included in the calculation for determining base rates is my understanding.

Q And so by virtue of the fact that those have, in the establishment of existing base rates, factored in a reduction of what would otherwise be paid by retail ratepayers, what you're saying is to then credit them through the fuel adjustment clause would be twice crediting that revenue. Is that the point that you were making?

A No, not really the point. Let's take the case of we've got rates set up for everything, okay. We're in motion, and now FERC comes along and says, okay, you have to charge a transmission component now of this sale. And, by the way, whatever transmission component you charge on a nonfirm sale, you have to credit the calculation of your firm transmission rates.

You have to next year when you reset your firm transmission rate, you have to give them credit for the fact that you have made money off nonfirm transmission revenue. That nonfirm transmission revenue will decrease from what you're able to charge then the next year, and eventually the customer has got to make that up, because it's -- you know, it's dollars flowing out.

Q When you say decrease, you're talking about decrease in the establishment of your wholesale rates the following year?

A No, we're not talking about wholesale; we're talking about transmission service.

Q On future year economy sales?

A Firm transmission. People use your system to wheel power across, you charge them a FERC approved rate.

Q That then FERC will approve for the following year -- you're saying then the following year FERC will take that revenue from this year and credit the revenue credit in calculating the rate for the following year's transmission?

A Well, before I say yes or no, let me clarify. The answer is yes, if what you meant when you said that revenue -- the nonfirm revenue that applies to the firm rate, because that's what they dictated in the order to do.

Q I'm sorry. Repeat that last part.

A If what you meant was do we take the nonfirm --

Q Okay --

A -- do we take the nonfirm transmission revenue and decrease the firm rate the following year, the answer is yes.

See, we've had firm rates and that they're at some level. Now FERC says, okay, we're now going to require you to take your economy transactions and assign or include a transmission component, and whatever that amount is, you've got to reduce the firm rate that you charge them next year. So you have less money.

So we give that money to them, and if the Commission decides, well, it's appropriate to take transmission revenues from economy transactions and give them to the customer through the fuel clause, the utility is giving twice. And we can't print the money, so we wound up short, and we're short on our base rates.

Q Then I'm missing the point of why you would then credit it through base rates for the surveillance reports as indicated on your Page 2 of your exhibit.

A Well, there are two ways that we can show this. We can show it being credited through the fuel adjustment clause as some are proposing, or we can show this being credited as operating revenue as some of the other utilities have suggested.

If you treat it as operating revenue that doesn't go through the fuel adjustment clause, it goes to base rates, and that shows up in this surveillance report.

Q When you are -- in the amount that you're calculating here or that you -- and I realize these are numbers that are simply used as examples -- but do I understand correctly that the $3 is not an incremental operating maintenance, but rather is an allocation of a portion of capital costs of the existing transmission facilities?

A Well, that's not a yes or no answer. The way the nonfirm rate is calculated is based on a combination of capital costs and O&M costs and all the other things that go into the calculation.

Q Then my question is, is this then an incremental cost that's being reflected here? Does it include a portion that's incremental, or is it rather --

A Well, it may or may not.

WITNESS HOWELL: Can I give an example, Commissioners, that will maybe clarify his question? Let's take the example of the southern Florida interface, which we know is somewhat fully subscribed in peak periods; and let's take the example that a power marketer -- Enron, LG&E, one of the many hordes that have come out recently -- are selling power to Florida, we then, if they use our transmission system to transmit that power down, we can charge them a third-party transmission component for the use of our system. And everybody agrees -- I think I've heard today -- that that third-party transmission would go into operating revenue. It's not a question of whether it should go into base rates -- I'm sorry -- whether it should go into fuel clause or not.

If we then say, well --

Q It's a question with us.

A I'm sorry?

Q It's a question with us.

A Okay. All right. Okay. Then there is a question. I stand corrected.

Rather than an LG&E using our system to sell power to Florida, if we then say okay, we're going to sell power to Florida because we can beat the rate or whatever, we have to take that same transmission -- exact same transmission component, and we then have to put that as a credit to the customer in the fuel clause, we're going to lose money, right? Do you follow my logic?

Q I understand what you're saying.

A And all I'm saying is, sometimes it could be an incremental cost, if you think of it, but look at it more as maybe it's an incremental loss if you don't treat it in base rates as opposed to trying to give it back through the fuel adjustment clause.

Q Thank you, Mr. Howell.

MR. STONE: That's all I have.

CHAIRMAN JOHNSON: Ms. Kaufman?

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Mr. Howell, I want to look also at your MWH-2, Page 2 of two, that Mr. Burgess was talking to you about. Do you want to turn to that?

A Yes, I have it.

Q And I want to talk about the bottom half that the bold heading says "Regulatory Treatment," and you've got four columns.

A Yes, ma'am.

Q The second column from the left is the "After" column; after 888, correct?

A Yes, ma'am.

Q And the very bottom line of that column using the hypothetical numbers that we've discussed all day shows $7 to the customer; is that correct?

A Yes, ma'am.

Q But it's true, isn't it, Mr. Howell, that of the $7, that $3 of transmission is being retained by the company in operating revenue?

A Well, it goes into operating revenue, and the customer pays all of our costs. So if the money didn't go there, he would have to make it up. So I see it going to the customer.

Q Well, my point is that $4 is going to the customer through the fuel clause, but the $3 is not; isn't that right?

A That's correct. It is not going to the customer through the fuel cost, it is going to the customer through a reduction in base rates.

Q Well, there's no reduction in base rates, is there, until the next time you have a rate case?

A There may be, if you overearn or the Commission calls you in.

Q You're correct.

A Yeah. I mean, I don't think we should fall into the trap of saying, well, as long as they don't have a rate case, there's no effect. There is an effect. One of the things that happens is we're growing all the time. As we grow, we get additional revenue from our customers, new sales. We get additional revenue for transmission that we sell. We have additional costs for expansion of our infrastructure that we have. And if the rates that are set by the Commission are adequate to maintain that balance, then there's no increase in rate. But all of this, in my view, the customer is benefiting from.

Q Well, just to be clear, Mr. Howell, I agree with you that unless the Commission brings you in and you're overearning, or unless you have a rate case, absent those two situations, that $3 is being retained by the company and there's no reduction for the customers.

A In your example, that's correct. If it's just $3, then certainly that's not going to swing a rate case or a call-in.

CHAIRMAN JOHNSON: Staff?

CROSS EXAMINATION

BY MS. PAUGH:

Q Mr. Howell, I believe you stated earlier that nonfirm transmission revenue would go to reduce firm transmission rates the following year; is that correct?

A Yes. No, I'm sorry. Would you repeat the question, please?

Q Nonfirm transmission revenue would go to reduce firm transmission rates?

A The following year; yes, ma'am, that's correct.

Q How does this reduction flow to the residential ratepayers specifically?

A Okay. Let's say we charge somebody -- in my prior example, we're going to charge -- let's say we're in balance, okay; whatever in balance means, as far as rates and revenue and profit and all that, okay. And we then make a sale, either from our resources off our system that results in $3 of revenue, or we let somebody else make a sale through our system and they pay us that results in $3 of revenue.

We then take that $3, and now we've got $3 more than what we need, and we're out of balance by $3. The next year we decrease the revenue that we get in firm transactions by an equal amount, and we're back in balance. So that flows directly to the customer and that the customer didn't have to make that up.

Q Okay. As part of the Southern Company, is Gulf a net purchaser or a net seller on the broker system?

A Okay. We don't participate in the Florida broker system. We do make economy transactions with Florida utilities, but not as a member of the broker system. Our transactions are through bilateral amendments to our interconnection agreements or through agreements with noninterconnected utilities or power marketers who want to buy or sell the power or use our system.

Q Within your agreements and amendments, are you a net purchaser or a net seller?

A We're generally a net seller.

Q What types of costs were included in Gulf's broker quotes prior to FERC Order 888?

A Broker quotes? You mean incremental costs?

Q Yes.

A It would be whatever the incremental cost of production is, which would include fuel, in-plant -- incremental in-plant fuel handling, incremental variable O&M, and we're going to ignore for a moment emission allowances, okay, since that's handled in the environmental cost recovery clause.

I think that's all -- don't hold me to it -- it's what I remember is included as far as what our incremental production cost is.

Q Okay. Thank you. Please refer to your Exhibit MWH-2. It's Page 2 of two of your exhibits. In that exhibit will you please explain Gulf's proposed methodology? Would ratepayers see an immediate impact of a $4 credit to the fuel clause just as before FERC Order 888?

A I'm sorry. Would you repeat that, please?

Q Based on that exhibit, would ratepayers see an immediate impact of a $4 credit to the fuel clause just like before FERC Order 888 was issued; is that correct?

A Yes, ma'am, that is correct.

Q Does this take into account any kind of jurisdictional separation?

A No, ma'am. One of the things that we did -- and I may remember it wrong -- but in the workshop that the Staff held with all the utilities, we tried to agree on numbers that everybody would use to where it would be easier to compare what the utilities are doing. So we came up with $20 as an incremental cost, $30 as a decremental cost, $3 as a transmission rate, and for simplicity, ignored things such as jurisdictional separation factors and the effect of in-plant fuel handling and all that. That was my understanding, and we filed it that way, and everybody but Power Corp filed it that way.

They also -- Power & Light and TECO also ignored this issue, and I think it's a relatively minor change as far as the jurisdictional separation. But, yes, we did; for purposes of simplicity here in trying to understand the differences, we did ignore that.

Q That's fine. When you make actual transactions, do you apply a separations factor?

A Well, when it comes time to assign the -- you know, if we're buying or selling, the answer is yes, we do take into account the jurisdictional separation factors; and all of the utilities, if they're doing it correctly, should do the same thing, and I believe they do.

Q Do you know what those percentages are, roughly?

A Roughly, it's about 96% retail.

Q Thank you.

A That's rough.

Q That's fine. Is it your testimony that under your methodology which is reflected in your exhibit the buyer flows the transmission costs directly to the ratepayer through the fuel clause, and the seller credits the transmission revenues to operating revenue?

A Yes.

Q Thank you.

MS. PAUGH: We have no further questions.

CHAIRMAN JOHNSON: Commissioners? Any redirect?

MR. STONE: Briefly.

REDIRECT EXAMINATION

BY MR. STONE:

Q Mr. Howell, just for the record, when you were referring to power marketers, you used a term. Would you mind spelling that term for the benefit of the court reporter?

A Power marketers?

Q No, no; the term you used to describe the power marketers. Would you please spell that for the record.

A Could you re-read that section there? What was the phonetic result of that?

MR. STONE: May I help the witness?

CHAIRMAN JOHNSON: Yes.

Q (By Mr. Stone) Was the word you used "hordes"?

A H-O-R-D-E-S, hordes. (Laughter) Hordes. I'm sorry. As in --

COMMISSIONER CLARK: You know, that's interesting. That's exactly the way I heard it, but he heard it differently.

WITNESS HOWELL: I refrain from any further comment, other than in my mind I was thinking of Hannibal crossing the Alps and the term paper I did in high school.

COMMISSIONER GARCIA: One of the definitions was pretty close to the truth. (Laughter)

WITNESS HOWELL: Well, he came with hordes of soldiers, and I picture -- you know, the power marketers have just become -- they have increased in number so exponentially that that's the word that came to mind; and I apologize for not seeing the potential tie between that and another -- whatever.

CHAIRMAN JOHNSON: Okay. Any other

questions?

MR. STONE: I did. But I won't.

CHAIRMAN JOHNSON: Exhibits?

MR. STONE: I would ask that we admit Exhibit 8.

CHAIRMAN JOHNSON: Show it admitted without objections.

(Exhibit 8 received in evidence.)

COMMISSIONER GARCIA: I'll just have you know, though, that Hannibal's soldiers weren't hordes, they were very well organized and disciplined.

WITNESS HOWELL: Yes, sir. And I didn't say -- the hordes only refers to the numbers of them. As a matter of fact, you're correct. The discipline of these men to cross the Alps in the winter was, I thought, incredible. No wonder they could defeat these people living a life of ease.

CHAIRMAN JOHNSON: Thank you, sir.

(Witness Howell excused.)

GERARD J. KORDECKI

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

DIRECT EXAMINATION

BY MR. WILLIS:

Q Would you please state your name, address, occupation and employer?

A Gerard J. Kordecki, 702 North Franklin, Tampa, Florida 33602, and I'm employed by Tampa Electric Company.

MR. WILLIS: Commissioners, we would propose to insert both Mr. Kordecki's prepared direct testimony and his rebuttal testimony in at this juncture and have him testify one time with respect to both of those.

CHAIRMAN JOHNSON: That will be fine.

Q **(By Mr. Willis)** Mr. Kordecki, did you prepare and cause to be prefiled "Prepared Direct Testimony of Gerard J. Kordecki"?

A Yes, I did.

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

A They would.

Q Did you have a exhibit attached to your testimony?

A Yes, I did.

MR. WILLIS: We would request that Mr. Kordecki's Exhibit GJK-1 be marked for identification.

CHAIRMAN JOHNSON: It will be marked as 9, identified GJK-1.

(Exhibit 9 marked for identification.)

Q **(By Mr. Willis)** Mr. Kordecki, did you also prepare and cause to be prefiled "Prepared Rebuttal Testimony of Gerard J. Kordecki"?

A Yes, I did.

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

A Yes, they would.

MR. WILLIS: We request that both Mr. Kordecki's direct and his rebuttal testimony be inserted in the record as though read.

CHAIRMAN JOHNSON: They will be inserted as though read.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

GERARD J. KORDECKI

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

A. My name is Gerard J. Kordecki My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company in the position of Senior Regulatory Consultant.

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

A. Yes. I have testified on behalf of Tampa Electric in a number of proceedings before this Commission. I have testified on conservation goals and program cost recovery issues, load research, cost allocation, rates and planning issues. A list of the dockets and testimony subjects is attached to my testimony as Exhibit 9 (GJK-1).

Q. What is the purpose of your testimony?

A. My testimony is intended to identify the effects of the

Federal Energy Regulatory Commission's (FERC) Order No's. 888 Final rule ("Open Access") and 888A (Order on Rehearing) on ("Open Access") on the terms, conditions and rates for transactions under the Florida Broker.

Q. Briefly describe how the recent "Open Access" rules require changes in the treatment of economy interchange?

A. The "Open Access" rule requires that each Public Utility unbundle the transmission and ancillary charges from its economy sales to all new customers effective July 9, 1996 and to all prior existing interchange contracts on January 1, 1997. A Public Utility must take service under its own unbundled transmission tariff for the purpose of transmitting power from its production capacity to the edge of its system for delivery to the buyer in the broker transaction. The revenues from these charges are to be recorded in separate revenue accounts. A utility must sign a transmission service agreement with itself which normally would be done between the company's bulk power sales function and its transmission department. This agreement covers all non-firm transactions of less than one year.

Q. Why has FERC required Public Utilities to take transmission service under their own tariff?

A. In order to facilitate the development of a competitive wholesale market, the FERC is requiring transmission owners to open up their transmission systems to potential users on a non-discriminatory, comparable basis which requires the owner to treat the use of its own transmission system for sales transactions as if the utility were purchasing transmission from a third party. The concept is to provide a level playing field so that generation competes directly against generation, thereby, denying a transmission owner the ability to discriminate in favor of its own power sales.

Q. Mr. Kordecki, has FERC specified how transmission revenue from broker transactions must be treated for wholesale transmission ratemaking purposes?

A. Yes. FERC requires that transmission revenues derived from all short-term transactions of less than one year be treated as a revenue credit.

Q. What does revenue crediting mean?

A. The revenues collected from short-term transmission services are subtracted from the overall transmission revenue requirements for purposes of determining FERC jurisdictional long-term transmission rates.

Q. What is the effect of revenue crediting on long-term transmission rates?

A. FERC revenue crediting effectively reduces the rate for all long-term transmission users by subtracting the transmission revenues received from short-term transmission sales.

Q. Can you give an example of how the required revenue crediting is accomplished?

A. Utility A has a transmission revenue requirement of $1,000 with an annual transmission peak demand of 100kW or $10 a KW/year or $0.83/KW/MO for firm long-term transmission users. Let's say utility A makes "Broker" sales which have a total transmission cost of $30. At the next transmission rate change the $30 of Broker revenue would be subtracted from $1,000 which in turn would reduce the transmission rate to $0.81/KW/MO ($1000.00 - $30.00 divided 12 months).

Q. Mr. Kordecki does FERC permit the addition of transmission charges to the sale quotes on the broker or transaction prices?

A. No. This approach would be contrary to the current position FERC has taken on split savings (page 204 of 888A) transactions.

> "In the cases cited by Utilities for Improved Transition, the Commission prohibited the utility from charging a split-savings rate plus a contribution to fixed costs. The Commission has long allowed utilities to set their coordination rates by reference to their own costs (cost-based ceilings) or by dividing the pool of benefits (fuel cost differentials) brought about by the transaction. Utilities have been free to design a rate using either method but not both." (emphasis added)

The precedent case citation is Illinois Power Company, 62¶ 61,147 to 62,062 (1993) and the pertinent paragraph states:

> "In Service Schedule F, Illinois Power proposes to charge a rate for economy energy transactions equal to a share of the savings plus its transmission charge of 10 mills/kWh. This is inappropriate. The Commission has long accepted

split-savings rates which disregard the fixed costs of the seller, but which ensure that the customer retains at least 50 percent of the transaction savings. Such rates permit the seller to obtain a contribution to fixed costs in excess of 100 percent, as long as the customer receives at least 50 percent of the savings. Illinois Power's proposed economy energy rate (allowing recovery of both a share of these savings plus a separate transmission charge) violates the Commission's pricing principles. Illinois Power retains over 50 percent of the savings, while Illinois Municipal receives less than 50 percent of the savings. Accordingly, Illinois Power is directed to revise Service Schedule F to eliminate the additional transmission charge."

It is clear that FERC will not allow a transaction which uses split-savings plus an added transmission charge. The FERC position also effectively requires a seller on the Broker to cover its transmission costs from its share of the split savings since the buyer must receive "at least 50 percent of the savings".

Q. Mr. Kordecki do you have any knowledge of any Florida Broker transactions after January 1, 1997 in which some of the transmission revenues are recorded above the line for revenue requirements calculations?

A. Yes, at the Commission Staff's workshop, utitlies stated that third party transmission revenues are being treated above the line for broker transactions.

Q. What are third party transactions?

A. Third party transactions take place when a seller must sell through another transmission system to reach a buyer. For instance, if Tampa Electric were making a Broker sale to Utility C but must use Utility B's transmission system, Utility B would require transmission wheeling revenues from Utility C in order to facilitate the sale. In this case, Utility B would receive the transmission revenue and that revenue would be credited above the line.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

GERARD J. KORDECKI

Q. Please state your name and business address.

A. My name is Gerard J. Kordecki My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q. Are you the same Gerard J. Kordecki who submitted Testimony in this proceeding on June 25, 1997?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to describe the inappropriate treatment of transmission costs proposed by Florida Power Corporation (FPC) and Florida Power and Light (FPL) for Schedule C Broker Sales. Each utility's proposal is inconsistent with Federal Energy Regulatory Commission (FERC) ratemaking policy and economic efficiency and may, possibly be discriminatory. I will also comment to the limited circumstance under which Gulf Power Company's (GPC) treatment of transmission costs is appropriate.

Q. Mr. Kordecki, how is FPC's treatment of the Transmission pricing inconsistent and possibly discriminatory?

A. FPC wishes to separate Schedule C Broker Sales participants into two categories -- those with agreements before January 1, 1997, and those who became members of the Florida Broker after that date. FPC proposes to treat transmission costs differently for "new" and "existing" participants. The net effect for "new" Broker customers would be a smaller share of the savings from a transaction than would accrue to an "existing" customer with an identical sale. This different treatment for "new" Broker customers has two significant shortcomings.

First, FPC cannot have a cost based split-the-savings sale in which the purchaser's benefits are less than 50 per cent of the total savings. The FERC position on shared savings is outlined in my direct testimony from line 5, page 5 and lines 1 through 17 on page 6 which requires that the buyer must receive "at least 50 percent of the savings" from the "pool of benefits (fuel cost differentials) brought about the the transaction."

Secondly, FPC wishes to discriminate between "new" and "existing" Broker customers through the method of allocating transmission costs when FPC is the seller. This situation is inconsistent with the purpose of the Broker matching system because it may lead to potential matches which are less efficient based on the fact that a customer is "new" instead of selection based on the difference in generating costs.

Q. Please comment on Florida Power & Light's proposal with respect to transmission pricing and treatment?

A. FPL wishes to treat the transmission it charges a Schedule C sale as if FPL's transmission grid were a separate company or a third party. This is accomplished by "adjusting the buyer's costs in the Broker matching algorithm just like it is done for transactions between non-directly interconnected utilities." (Villar page 3, lines 10 through 13.) Again, as in the FPC's proposed "new" customer situation, FPL will retain more than 50 per cent of the transaction savings which is contrary to FERC regulations. This approach, moreover, raises the same issues on economic efficiency noted above.

Q. Mr. Kordecki, is there any further problems in the FPL proposed methodology?

A. Yes. FPL states that "through this methodology, FPL's Broker sales are treated the same as Broker sales by other users of FPL's transmission system." For pricing this statement appears to be correct, but for transmission revenue treatment, FPL does not treat its Broker sales and the Broker sales of others symmetrically. In third party transactions, FPL keeps transmission revenue as operating income. With respect to its Broker transactions, FPL proposes to flow transmission revenues through to the fuel clause.

From the Staff workshop, it is also my understanding that FPL's treatment of transmission for all other third party non-Broker short-term sales is to credit these revenues to operating income. This treatment is consistent with the FERC required revenue crediting treatment but differs from their Schedule C proposed treatment. In order to be consistent with both transmission usages and ratemaking principles, FPL should treat transmission revenues from Broker sales as "above the line" so that transmission revenues are treated comparably for all of FPL's short-term transmission uses whether it be for FPL's use or a third party's.

Q. What are your comments concerning Gulf Power's pricing methodology for shared savings transactions?

A. Gulf Power, of course, is not a participant in the Florida Broker system so its proposal is hypothetical only. Southern Company (Southern) actually makes all transactions under market based rates. The latter point is most important. If Southern were making sales under a (regulated) cost based regime, their proposed treatment (split savings on generation plus full transmission charges) would be contrary to FERC policy as stated previously in my testimony. With market-based rate authority, even if the negotiated price is based on a shared savings methodology, Southern must treat its transmission costs for the sales separate from the generation price, no matter if Southern or the buyer is the transmission customer.

In essence, Gulf Power's proposed treatment of transmission revenues is proper only because it has market-based rate authority, which none of the peninsular Florida public utilities have acquired for off-system sales in Florida. Therefore, Gulf Power's situation differs significantly from the other Broker participants.

Q. Mr. Kordecki, does this conclude your rebuttal testimony?

A. Yes, it does.

Q (By Mr. Willis) Would you please summarize your testimony?

A First, the summary of my direct testimony. Actually, I wrote down "good morning," but I guess we can go by that at this point.

My direct testimony addresses the unbundling effect for FERC Orders 888 and 888A which require public utilities to separately account for generation, transmission and ancillary services when making off-system sales.

For short-term transactions, the FERC requires utilities to revenue credit or reduce transmission revenue requirements when -- which effectively is treated as operating income. Broker sales is just one category of short-term transactions. Others would include opportunity sales and third-party transmission transactions.

Since the Florida energy broker is a cost based shared savings market, FERC has required that, first, the buyer must receive at least 50% of all benefits. Second, the transmission charges cannot be added to the variable cost differentials.

With these constraints, Tampa Electric has designed its broker sales transactions so that the transmission costs that are captured from Tampa

Electric Company's share of the -- excuse me -- that the transmission costs are captured from Tampa Electric's share of the transaction savings, therefore, meeting both of FERC's pricing criteria.

And rebuttal: My rebuttal testimony addresses the utility's proposed pricing methodologies for shared savings transactions. Both the FPC new customer proposal and FPL's proposal for pricing treatment of broker transactions suffer from serious deficiencies in meeting FERC pricing criteria, but each of those utilities has a pending filing at the FERC, and litigation will resolve any problems in pricing.

Further in my rebuttal I address some inconsistencies in the treatment of transmission revenues for similar transmission transactions. These differences in revenue treatments should be resolved by this Commission in this proceeding.

Thank you.

CHAIRMAN JOHNSON: Thank you.

MR. WILLIS: We tender the witness.

CHAIRMAN JOHNSON: Florida Power & Light?

CROSS EXAMINATION

BY MR. CHILDS:

Q Would you turn to Page 3 of your direct testimony, specifically looking at the answer beginning on Line 19 when you state that the FERC requires that transmission revenues be treated as a revenue credit?

A That's correct.

Q Where is that provided by the FERC?

A Excuse me a second. (Pause) Page 247 of the rehearing. I'll read --

Q I'm sorry. Of the what?

A Of the rehearing order, which is 888A. "In order to prevent overrecovery of costs from those, use this approach." The Commission explained that it will require transmission providers to include firm point-to-point capacity reservations in the derivation of the low ratio calculations for billings under network service.

In addition, the Commission explained that revenue from nonfirm transmission services should continue to be reflected as a revenue credit in the derivation of firm transmission tariffs, rates.

Q Does FERC have any directions about how revenue from broker transactions that do not include compensation for transmission be credited?

A I have --

Q Doesn't FERC also tell you to credit the revenue from a broker sale?

A The transmission --

Q Direct --

A The transmission portion?

Q No, the nontransmission portion.

A No.

Q They don't?

A No.

Q Does this Commission tell you that?

A I couldn't tell you what the Commission tells us. I'm not testifying to that.

Q Well, isn't it this Commission that affects the recovery of costs for retail ratemaking?

A Yes.

Q I want to show you a document, please.

MR. CHILDS: Commissioners, I have given the witness a document which is entitled "Staff Advisory Bulletin No. 20, two pages issue date shown as being 9/14/84 in the upper left-hand corner and effective date of 1/1/85.

Q **(By Mr. Childs)** Mr. Kordecki, have you had a chance to look at this document?

A Briefly, yes.

Q Do you know whether this document directs the accounting associated with broker transactions in the state of Florida?

A Yes, it does.

Q Do you know whether the FERC order having to do with the crediting of revenue for transactions for wheeling in broker sales directs that the crediting be to a sub-account of Account 447?

A Yes, it does.

Q And 447 is the same account to which this accounting bulletin directs that the nonwheeling portion be credited, is it not?

A Yes.

MR. CHILDS: I'd like to have that document marked for identification Commissioners, that bulletin No. 20.

CHAIRMAN JOHNSON: It will be marked as Exhibit 10, short titled Staff Advisory Bulletin 20.

(Exhibit 10 marked for identification.)

Q **(By Mr. Childs)** Mr. Kordecki, as to the treatment and your comment about the inconsistent treatment by the other companies both, I think, in your direct and rebuttal, I ask you the following: Would you agree that prior to 1985 when broker sales were treated exclusively in the fuel adjustment clause, that the off-system sales revenues for broker transactions were handled in a full rate case proceeding by reducing retail revenue requirements by an imputed amount of budgeted off-system sales revenue?

A That's correct.

Q And would you agree that that treatment or recognition was through crediting?

A Excuse me. Are you still addressing my direct testimony, or my rebuttal testimony?

Q I'm addressing at this point your point about what FERC directs you to do in terms of crediting.

A All right; summary of my rebuttal.

Q Would you agree that it -- that this Commission reflected the treatment of revenues from the sale -- broker sales, through a crediting of revenues against the retail revenue requirement?

MR. WILLIS: Excuse me, Mr. Childs. What is your reference to his direct testimony?

MR. CHILDS: I'm referring still to his testimony on Page 3 of his direct which asks has FERC specified how transmission revenues must be treated for wholesale transmission revenue purposes, and he answers that. And then in his -- and I asked him whether that determined how the transaction needed to be addressed in the state of Florida.

And so at this point I'm trying to understand the consistency or relationship between the crediting as directed by FERC and the crediting as directed by this Commission.

WITNESS KORDECKI: The term that I used in my summary of rebuttal that said about inconsistencies did not refer to treatment by this Commission; it referred to treatment of transmission transactions that used the same -- basically, let's say the nonfirm transactions or short-term firm transactions in some cases were being dealt with by this Commission, specifically broker sales, as credits to the fuel clause as opposed to in other types of sale, let's say third-party sales or other types of sales where the revenues were taken above the line as operating income.

So maybe I didn't make it clear when I summarized my rebuttal that it was specific to transmission, not that there was inconsistencies in the treatment of where brokered sales were being dealt with by this Commission.

Q **(By Mr. Childs)** And would you agree, though, that the methodology used by this Commission prior to the inclusion of broker revenues in the fuel adjustment clause was to credit an estimated level of the revenues against the retailed revenue requirement in setting retail base rates?

A Yes, that's fine.

Q And would you agree that when this Commission changed to incorporate broker transactions in the fuel adjustment clause, that it, in fact, addressed the retail rate level to reflect that change; that is, that the amount of revenue that was being transferred to the fuel adjustment clause was reflected in an adjustment to base rates for the effective utilities?

A I'll take your word for it. I wasn't there.

Q Well, I'm going to show you an order. It's Order 12923 dated 1/24/84, and I'm going to ask you to look at Page 3. I have one copy, so I'm going to identify it in advance.

MR. WILLIS: Chairman Johnson, I object to this line of questions which are beyond the scope of Mr. Kordecki's testimony. Mr. Kordecki's testimony goes to what the FERC treatments are, and he is asking him a different line of questions that is not relevant to his direct testimony. Those questions, if they're to be directed, should be directed to Witness Branick.

CHAIRMAN JOHNSON: Mr. Childs?

MR. CHILDS: I think the witness just tried to steer me in the right direction when he told me what he was testifying in his direct testimony to about the differential in the treatment between the FERC and the FPSC.

I mean, to talk about what the FERC requires without it having some relevance to what this Commission does, I think would make all this testimony relevant. My understanding was the witness said that the FERC requirements were applicable to the consistency of the treatment of the cost by this Commission, and I think those were his words, "the consistency."

CHAIRMAN JOHNSON: I'm going to allow the question.

Q **(By Mr. Childs)** Mr. Kordecki, would you look to that order that I gave you, Page 3 --

A Yes.

Q Would you look to that highlighted paragraph towards the bottom of the page and tell me if you would agree that that order reflects that the Commission, in fact, adjusted base rates at the time that it changed the treatment of broker sales in the fuel adjustment clause?

A Yes, that's what it says.

Q Would you agree that now we're going in the other direction, that is as it relates to the transmission revenue, the treatment that you propose, that you are proposing a credit to revenue, which you state the FERC directs?

A My company's proposal is that it'd be more appropriate to credit operating income with short-term firm and nonfirm transaction; that's correct.

Q And the effect of that would be to take that amount of the revenue associated with transmission revenues from the fuel adjustment clause first of all, would it not, by crediting as you propose?

MR. WILLIS: Excuse me, Mr. Childs. Our witness for what our company proposal is is Ms. Branick, not Mr. Kordecki. Those questions should be directed to Ms. Branick.

MR. CHILDS: My understanding was this witness in his rebuttal testimony and in his summary testifies about that treatment by this Commission. I realize you may have intended that the other witness address it, but my understanding was that this witness is talking about that treatment and the impact of that treatment because of the crediting as directed by the FERC. And the witness is testifying as to the effect of the crediting on the long-term transmission rate, and I don't understand how you can affect the long-term transmission rate without reflecting the impact on revenue requirements at the retail level. So I'm trying to see how that's consistent.

WITNESS KORDECKI: They are not consistent.

Q (**By Mr. Childs**) They're not consistent?

A No. The retail rates are done -- in the retail jurisdiction, the -- they're basically done on a separation basis. In other words, requirements, wholesale and retail, basically take -- or take all the revenue requirements.

In the FERC jurisdictional transmission rates, long-term firm use of the system, excluding -- including both native load requirements and third-party users, basically the rate is derived as if the third-party users of the transmission system were, in fact, owners of the system.

In other words, the revenue requirements are divided by the demand of all the firm customers on the system, including retail, wholesale requirements and third-party users. So there is a discrepancy between the two.

Q Let me refer you specifically. Perhaps we can head off some concern about the scope of the questions. Would you look at Page 4 of your rebuttal testimony?

MR. CHILDS: And I would point out that there this witness is attempting to rebut the testimony of Florida Power & Light Company and says as follows: In third-party transactions, FPL keeps transmission revenues as operating income. With respect to broker transactions, FPL proposes to flow transmission revenue through to the fuel clause.

Q (By Mr. Childs) Are you addressing that in the context of wholesale transactions or FERC transactions?

A Yes. Those are all --

Q All of this testimony relates solely to the FERC?

A All wholesale transactions are FERC jurisdictional; that's correct.

Q No. But this testimony where we say "With respect to broker transactions, FPL proposes to flow transmission revenues through to the fuel clause," that testimony relates to what FPL proposes to do for wholesale sales?

A For transmission transactions?

Q Yes.

A Yeah. That's --

Q The flowing through is for the flowing through in the wholesale fuel adjustment clause?

A No. I said --

Q Retail fuel adjustment --

A Yeah, in either -- either clause.

Q So to the extent we're talking about the retail fuel adjustment clause, we have to talk about what this Commission has before it, don't we?

A Yeah. I mean --

Q To the extent we talk about what's proper and consistent, we have to talk about what this Commission has directed and authorized, don't we?

A As far as all sales?

Q That's right.

A Yes.

Q Well, now let me go back to the question. When this Commission directed that the cost be included in the fuel adjustment clause, I think you testified that it adjusted base rates.

A That's correct.

Q And it did that for Tampa Electric Company, correct?

A That's correct. Yes.

Q Now, your proposal is to credit revenue, I think, for retail purposes; is that right, to the extent of the transmission revenues associated with broker transactions?

A Again, I'm not the witness. But the Company's proposal is that all short-term transactions less than a year ought to be revenue credited, which is in essence crediting to operating income. That includes broker opportunity sales and third-party short-term use --

Q Sure. And you --

A -- transmission --

Q You -- excuse me. Are you finished?

A Yes.

Q You say on Page 4 of your rebuttal testimony, "In order to be consistent with both transmission usage and ratemaking principles, FPL should treat transmission revenues from broker sales as, 'above the line,' so that transmission revenues are treated comparably for all of FPL short-term transmission uses," et cetera, don't you?

A That's the principle I believe is correct, yes --

Q And do you mean that principle should be one that's applicable in the retail context, or only wholesale?

A You're talking about retail rates as opposed to retail transmission use?

Q I'm talking about retail rates as related to the fuel adjustment and broker transactions.

A I think all short-term transactions should be dealt with the same way, whether third party or broker, whatever they be; yes, that's --

Q So my question is -- well, I'm just asking you to confirm the scope of your testimony, whether it's wholesale or retail in the content --

A I think -- the scope of my testimony is, is that all those transactions, like transactions, should be treated the same way.

Q Okay. And now treating them the same way when we go back to the question of including the revenue from wheeling for broker transactions or sales by Tampa Electric as a credit to revenue. That is the proposal, right?

A Yes.

Q Credit to revenue, above the line?

A Above the line.

Q But it does not include -- that is the proposal -- an adjustment to rates?

A Well, I would think that would be appropriate, yes.

Q You think it would be appropriate?

A Yes. If you're going to take it out of one and put it in the other, yes.

Q In fact, that's what the Commission did before when it was going the other way, didn't it?
A Yes.
Q Thank you.
MR. CHILDS: That's all I have.
CHAIRMAN JOHNSON: Florida Power Corp?
MR. McGEE: No questions.
CHAIRMAN JOHNSON: Gulf?
MR. STONE: No questions.
CHAIRMAN JOHNSON: Public Counsel?

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Kordecki, I want to go back to the example that was used, $30.00, $20.00 and $3, to understand how you would suggest the transaction price be calculated.

When we have that, as I understand it, if TECO were the selling utility, you suggest that the transaction price would be $25 and that the $3 simply be subsumed within that?
A That's correct.
Q My question to you is, do you have in this an understanding or a notion as to what then would be the cost in the same situation, but let's say there was also an alternative source of production that was

$18 strict --

A Mr. Burgess, could I ask you something? I did not prepare the exhibit that you're generally addressing, and I think it would be more appropriate if you'd address those questions to Mrs. Branick.

Q Okay. Now, I'm --

A I mean, I can -- I'll -- you know, I can attempt to answer, but I think she's the one testifying to the specifics.

Q Well, I'm addressing Issue 11 and Issue -- I mean, addressing Issues 9 and 11. I'm not addressing -- I'm trying to figure out the transaction price. I'm not dealing with how it should be treated in the ratemaking context.

A I'm sorry.

Q If, for example, there were an alternative production source available at 18, but they needed wheeling services from TECO to make that sale, what would be the transaction price there in your understanding of the post-888 process?

A Well, I don't -- if it was a broker transaction, it wouldn't have been any different than it was before. The buyer would have purchased transmission service from us, and to the extent that the margin difference was still greater, they would buy or not buy. I think that's --

Q Okay. Well, let me run through the arithmetic just to make sure that we have the same understanding as to whether the sale would be made.

As I understand it, then the producer at 18 would add $3 and so, therefore, the price would be -- the incremental price would be $21, and the split-the-savings with the potential buyer would, therefore, be $25.50 and, therefore, the sale would be made from Tampa Electric?

A Yeah. I'll take your --

Q Okay. And I guess my question -- and once again this gets down to what we all agree is a very difficult question to answer, and there doesn't seem to be any silver bullets here -- but doesn't that, the fact that with those examples the $20 future as far as costs for production would be sold instead of the $18 fuel, doesn't that run counter to what you state on Page 3 of your testimony, of your direct testimony wherein you began on Line 9 that the concept -- and this is the concept of 888 is to provide a level playing field -- and I knew that term was used by somebody somewhere -- so that generation competes directly against generation?

A That's correct.

Q And in the example that we've come up with, if the relationships of the numbers are in that category, then, in fact, we wouldn't have -- under the proposal that you have, we wouldn't have generation competing directly against generation?

A No, I disagree.

Q Oh. Please tell me how.

A I think the concept of the level playing field was the fact that a transmission owner could, in fact, not charge for transmission and make a sale against a third party who had to pay the fee to get across the system. So that the idea of revenue crediting or charging, it does, in fact, level the playing field, at least in terms of operating income that has to be regulated. Everyone is paying the same charge.

One is imputed this -- you know, as an owner, it's imputed at this point and would be dealt with, I guess, in a rate case or, you know, it would be a subtraction from revenue requirements. That's how it's dealt with. And to the extent that there was a third-party marketer who had to pay the $2, or whatever it be, they don't have the same direct effect, but ultimately they do.

Q My understanding of what you had indicated in the example was that, in fact, at that particular hour if those were the available alternatives, the broker would direct the burn of the $20 fuel as opposed to the $18 fuel.

A Well, I think it's still -- you've got two things you're -- that are trying to be accomplished. You're trying to match the lowest cost generation, but you're also trying to keep all the parties on the same level playing field.

To the extent that the higher cost generation might be used as opposed to the lower cost, that may be one of the outgrowths of competition.

Q I see. So then it would run afoul, at least of the understood purpose of the broker, which is to burn the lowest cost fuel available?

A Well, if -- in using your example, let's say it was -- you know, one was 18 and one was 20, whatever it be, and that --

Q And a $3 dollar transmission --

A And a $3 transmission, I think that -- I will attempt to speak for Tampa Electric Company and the other utilities -- and they can jump up and say that I'm wrong -- is one of the obvious -- the obvious problem is that if we were to discount down to the generation only cost, in other words, transmission was zero in every hour for broker transactions, and broker transactions are quoted every hour of the year, that in fact would mean that marketers, IPPs or other people with generation could traverse the transmission system for nothing.

Q Yes.

A It would be free to everyone.

Q Yes. And it would --

A That's --

Q And it would assure that the lowest production cost at any one time would be that which --

A No. That would mean that you're getting no revenues for your transmission system, number one, the owner. Number two is that in all probability, that would be serving loads that probably would be removed from Florida utilities service and they would not be making the sale.

So I suspect what you're really saying is, yes, you may end up with the lowest cost generation, but you're going to end up with -- in that case, but you're going to also end up with a lot of stranded cost in the sense that the revenue is not being met elsewhere.

Q Thank you.

CHAIRMAN JOHNSON: Ms. Kaufman?

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Mr. Kordecki, would you agree with me that if the transmission revenue from these transactions we've been talking about is credited through the fuel clause, that consumers will see an immediate reduction in their bills?

A Yes, they would see -- yes, they would.

Q And that would not be the case if these revenues are retained as operating revenues as you proposed; is that right?

A There they would see them in terms of -- when rate changes were made or in terms of the effect of the earnings of the company. So they ultimately would see those benefits anyway.

Q They wouldn't see an immediate reduction, would they?

A No.

Q You were here, weren't you, when Mr. Villar testified?

A Yes.

Q And is it your understanding that at least as to broker transactions -- and we may have some disagreement on the wheeling, as Mr. Burgess mentioned -- but at least as to broker transactions, FPL is proposing to flow the revenues back through the fuel clause?

A That was my understanding.

Q And I am correct in understanding that it's Tampa Electric's position that you want this Commission to direct FP&L not to do that and to require them to retain those revenues as operating revenues?

MR. WILLIS: Excuse me just a minute. These questions are well beyond the scope of Mr. Kordecki's testimony. We have another witness that states what the appropriate treatment should be. Her name is Ms. Branick. She's the next witness, and these questions should be directed to her.

MS. KAUFMAN: Chairman -- I beg to differ with you. If you look at Mr. Kordecki's rebuttal testimony, Page 4, beginning approximately at Line 8, he's directly criticizing there what FPL is proposing to do, and I think I'm entitled to question him about that.

CHAIRMAN JOHNSON: Mr. Willis?

MR. WILLIS: The fact that he mentions that in his testimony is not indicative of whether he's sponsoring the particular treatment for Tampa Electric. He made those statements. The treatment and the proposal that we have made is being sponsored by Ms. Branick.

CHAIRMAN JOHNSON: I'm going to allow the question. To the extent that the witness doesn't known the answer or can't answer it, then he can say something.

Q **(By Ms. Kaufman)** Do you need me to repeat the question, Mr. Kordecki, or do you recall it?

A Yeah. The essence of my statement is, is that for consistency's sake, they ought to be dealt with the same way, and the Company's proposal is that they be dealt in operating income.

Q So what you are asking this Commission to do is to direct FPL to not flow these revenues back to ratepayers; is that right?

A I think they're flowing them back when they put them above the line. You just asked me whether it was immediate or longer term, and the answer I gave you was not immediate, it was longer term; but I am saying they ought need to be -- they are being flowed back.

Q Well, maybe my question wasn't clear. What you're asking the Commission to do is to direct FPL not to flow these revenues back to customers through the fuel clause; is that right?

A Companies -- Tampa Electric's proposal, you need to direct that to Ms. Branick. I'm just saying --

Q Mr. Kordecki --

A I'm just saying they need to be treated the same way.

Q If you would look at your rebuttal testimony on Page 4 beginning at Line 9. If I'm misreading this, you know, just tell me; but aren't you criticizing FPL there and suggesting that the Commission should direct them to follow the approach that Tampa Electric is sponsoring?

A I think what I was attempting to do was show that there's an inconsistency between -- in terms of how transmission use is being dealt with, and to the extent that the more appropriate treatment for purposes of revenue crediting because -- due to the FERC transmission tariff is operating income, yes.

Q You think that's a more appropriate treatment for FPL to use as well?

A I think it's a more appropriate treatment for everybody to use, yes.

Q Now, I think you mentioned in some responses to me and earlier as well that one of your concerns is that all these transactions be treated in the same way; is that right?

A Yes.

Q And the way that Tampa Electric has proposed that consistency is to retain all the revenue from all the different kind of transactions as operating revenue, right?

A Short-term, yes.

Q Wouldn't another way to maintain consistency be to flow back all the revenue through the fuel clause from these transactions, treat them all that way?

A Well, not all, no. You can't flow all of it back.

Q We're talking about transmission revenues here.

A That's hard to say.

Q So another way to assure consistency would be to flow the revenues back, rather than retaining them as operating revenue?

A No. I think actually the most equitable way is to leave them above the line, because they're -- above the line you're dealing with both retail in a rate case, wholesale requirements in a rate case, and third-party users in a -- in a case.

Q Mr. Kordecki, I think I understand Tampa

Electric's position, but what I'm asking you is, it certainly would be a consistent treatment to flow the revenue back, wouldn't it?

A I don't think there's a way to consistently flow back third-party users. That's what I'm saying.

Q I guess I don't understand your response. Why could Tampa Electric not take the revenue that it receives from third-party transactions and flow it through the fuel clause?

A Because third-party users, nonrequirements customers don't have a fuel clause.

Q We're talking about retail customers here, right? I think you got in that discussion with Mr. Childs. We're talking about retail customers and the retail --

A And I'm saying because of those differences between requirements, retail and third-party users, the most equitable way to deal with it is to put it in operating income.

Q Let me give you a hypothetical. Maybe we can work through this. If Tampa Electric --

MR. WILLIS: Excuse me. I object to this continuing line of questions with respect to Tampa Electric's proposal. These questions should be directed to Ms. Branick.

MS. KAUFMAN: Chairman Johnson, I think I understand Tampa Electric's proposal, and that's not what I'm questioning Mr. Kordecki about.

He's stated several times that one of Tampa Electric's concerns is that these revenues be treated consistently, and that's what I'm trying to explore with him. He stated what Tampa Electric's consistent treatment would be, but I think there are other ways to deal with it.

WITNESS KORDECKI: And what I'm saying is that there's no consistent way to deal with a third-party user -- in a fuel clause. There is no fuel clause.

CHAIRMAN JOHNSON: I will allow the question.

MS. KAUFMAN: Thank you.

Q **(By Ms. Kaufman)** Here's my hypothetical, Mr. Kordecki. Tampa Electric receives revenue for transmission service that it has provided to one of these third-party hordes that Mr. Howell referred to. They receive that revenue. It's accounted for. Why is it they could not flow through the fuel clause?

A Because the customer who -- where you derive the rate from FERC does not have a fuel clause.

Q But Tampa Electric could take that revenue and flow it through the retail fuel clause which we have in Florida, right?

A Then you will have the mismatch that Mr. Howell was deriving. You're giving away, theoretically, someone else's money.

Q But you could do it. I mean, it's not a problem of accounting. You could flow it through the fuel clause.

A I could flow everything through the fuel clause. I mean, accounting wise, we could put everything through, yeah. I'm not trying to be capricious, but that's -- yes. It doesn't make it right.

Q Thank you.

MS. KAUFMAN: That's all I have, Chairman Johnson.

CHAIRMAN JOHNSON: Staff?

MS. PAUGH: Staff has no questions of this witness.

CHAIRMAN JOHNSON: Redirect?

MR. WILLIS: Could we take a short break?

CHAIRMAN JOHNSON: We'll take a five-minute break.

(Brief recess.)

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Q (By Mr. Willis) Mr. Kordecki, Mr. Childs asked you several questions with respect to the treatment of transmission revenues above the line, and the effect of those treatments with respect to the company's base rates. Do you recall those questions?

A Yes.

Q Mr. Kordecki, when should those revenues and the calculation of those revenues affect the company's base rates?

A At the time of the next rate case is what I meant.

Q Now, you were also asked some questions with respect to the actions taken in 1984 at the time the 80/20 split was adopted?

A Yes.

Q Do you know, in fact, if Tampa Electric's base rates were changed at that time?

A No, I do not. It was my understanding, and I could stand corrected, that they were done at the next rate proceeding.

Q Thank you.

MR. WILLIS: No further questions.

CHAIRMAN JOHNSON: No further questions? Exhibits.

MR. WILLIS: Mr. Kordecki's Exhibit No. 9, I believe, I move into evidence.

CHAIRMAN JOHNSON: Okay.

MR. CHILDS: I'd like to move Exhibit 10.

CHAIRMAN JOHNSON: Show both those admitted then without objection. Thank you. You're excused.

(Witness Kordecki excused.)

(Exhibits 9 and 10 received in evidence.)

MR. WILLIS: Call Ms. Branick.

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KAREN BRANICK

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

DIRECT EXAMINATION

BY MR. WILLIS:

Q Would you state your name, address, occupation and employer?

A My name is Karen Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I'm employed by Tampa Electric Company and I'm the Director of Electric Regulatory Affairs.

MR. WILLIS: Chairman Johnson, Ms. Branick filed three different pieces of testimony. The first two pieces have been stipulated in the record, as I understand, and the third piece, the supplemental direct testimony is the subject that we're trying on transmission revenues. And I take it, it was not shown as stipulated in by asteric, but I'm asking that her testimony and exhibit, prepared Direct Testimony of May 20th, as well as the prepared Direct Testimony of June 23rd, be inserted into the record, and that the exhibits attached thereto be admitted in the record.

CHAIRMAN JOHNSON: May 20th was stipulated?

MR. WILLIS: Yes. The first two pieces were stipulated into the record, I believe.

MS. PAUGH: Yes, they were stipulated, but we've not identified the additional exhibits. We'll do that at the --

CHAIRMAN JOHNSON: So all we need to deal with now is the -- but we will go back and take care of that in a orderly fashion. As it relates to her testimony are we looking at the June 23, '97?

MR. WILLIS: That's correct.

CHAIRMAN JOHNSON: You said there were exhibits attached to that?

MR. WILLIS: There is one exhibit attached to that, KAB-5.

CHAIRMAN JOHNSON: And the rebuttal was to Issue 13 so it's been withdrawn?

MR. WILLIS: It's been withdrawn.

Q **(By Mr. Willis)** Did you prepare and cause to be prefiled Supplemental Direct Testimony of Karen A. Branick?

A I did.

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

A They would.

MR. WILLIS: We'd ask that Ms. Branick's supplemental direct testimony be inserted into the record as though read.

COMMISSIONER JOHNSON: It will be so inserted.

Q **(By Mr. Willis)** Did you prepare an exhibit that's attached to your testimony?

A KAB-5?

Q Yes.

A Yes.

MR. WILLIS: I ask that exhibit be marked for identification.

CHAIRMAN JOHNSON: It will be marked Exhibit 11 identified KAB-5.

(Exhibit 11 marked for identification.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN A. BRANICK

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

A. My name is Karen A. Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues in the Regulatory and Business Strategy Department of Tampa Electric Company.

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

A. I received a Bachelor of Science Degree in Chemical Engineering and Chemistry from the University of Pittsburgh, Pittsburgh, Pennsylvania in 1986. In 1987 I was employed as a chemist for Florida Power & Light Company (FPL). In 1990, I became a performance engineer; in 1991 a lab supervisor; and in 1992 an operations supervisor for FPL. My career at Tampa Electric Company began in 1992 in the Production Department. My responsibilities included insurance of proper boiler chemistry and chemical engineering support during normal operations and maintenance outages. I led projects related to alternate fuel test burns and waste water management. In 1994, I transferred to the Bulk Power & Market Development Department where I managed the customer accounts of approximately 30 of Tampa Electric's large industrial customers. I also participated in developing proposals for long term off system sales of wholesale power. In October of 1996, I was promoted to Manager-Energy Issues in the Regulatory and Business Strategy Department. My present responsibilities include the areas of fuel adjustment, capacity cost recovery, environmental filings and rate design.

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

A. The purpose of my testimony is to present the net true-up amounts for the October 1996 through March 1997 period for both the Fuel Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel cost recovery clause for the period October 1996 through March 1997?

A. An over/(under) - recovery of $1,926,965. The actual fuel cost over/(under) - recovery, including interest, is $6,918,724 for the period October 1996 through March 1997 (Schedule A2, page 2 of 3, of March 1997 monthly filing, in Document No. 4, reflects an end of period total net true-up of $3,517,588. Subtracting the beginning of period deferred true-up of ($3,401,136) yields the $6,918,724. This $6,918,724 amount, less the actual/estimated over/(under) - recovery approved in the February 1997 fuel hearings of $4,991,759 results in a final over/(under) - recovery for the period of $1,926,965. This over/(under) - recovery amount of $1,926,965 will be carried over and applied in the calculation of the fuel recovery factor for the period October 1997 through March 1998.

Q. How much effect will this $1,926,965 over/(under) -recovery in the October 1996 through March 1997 period, have on the October 1997 through March 1998 period?

A. The $1,926,965 over/(under) - recovery will cause a 1,000 KWH residential bill to be approximately $0.27 lower.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. Exhibit No. (KAB-1, Fuel Cost Recovery and Capacity

Cost Recovery) which contains four documents. Document No. 3 is used to explain the capacity cost recovery clause which is discussed later in my testimony. Document No. 4 contains Commission Schedules A-1 through A-9 for the months of October 1996 through March 1997. Included with the March 1997 monthly filing is a six months summary for each of Commission Schedules A6, A7, A8, and A9 for the period October 1996 through March 1997.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over/(Under) - Recovery for the period October 1996 through March 1997" shows the calculation of the final fuel over/(under) - recovery for the period of $1,926,965 which will be applied to jurisdictional sales during the period October 1997 through March 1998.

Line 1 shows the total company fuel costs of $151,404,489 for the period October 1996 through March 1997. The jurisdictional amount of total fuel costs is $152,930,406 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 over/(under) - recovered fuel costs for the period, shown on line 4. The resulting

$6,959,567 over/(under) - recovered fuel costs for the period, combined with ($40,843) of interest shown on line 5, constitute the actual over/(under) - recovery of $6,918,724 shown on line 6. The $6,918,724 less the actual/estimated over/(under) - recovery of $4,991,759 shown on line 7, which was approved in the February 1997 fuel hearings, results in the final over/(under) - recovery of $1,926,965 shown on line 8.

Q. What does Document No. 2 show?

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period October 1996 through March 1997," shows the calculation of the actual over/(under) - recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period October 1996 through March 1997?

A. As shown on line C1 of my Document No. 2, the company collected $10,517 more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period October 1996 through March 1997?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is ($6,023,729) or (3.8%).

Q. What are the reasons for the total fuel and net power transactions cost being lower by ($6,023,729) or (3.8%)?

A. The primary reason for the (3.8%) decrease is due to Net Energy for Load being up 37,497 MWH or 0.5%. This 0.5% combined with the ¢/KWH for Total Fuel and Net Power Transaction being less than estimated by (4.3%), accounts for the (3.8%) decrease.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period October 1996 through March 1997?

A. An over/(under) - recovery of ($28,551). The actual capacity cost over/(under) - recovery, including interest, is $212,386 for the period October 1996 through March 1997 (Document No. 3, pages 2 and 3 of 5). This amount, less the actual/estimated over/(under) - recovery approved in the February 1997 fuel hearings of $240,937 results in a final over/(under) - recovery for the period of ($28,551) (Document No. 3, page 5 of 5). This over/(under) - recovery amount of ($28,551) will be carried over and applied in the calculation of the capacity cost recovery factor for the period October 1997 through March 1998.

Q. How much effect will this ($28,551) over/(under) - recovery in the October 1996 through March 1997 period, have on the October 1997 through March 1998 period?

A. The ($28,551) over/(under) - recovery will have no effect on a 1,000 KWH residential bill.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN A. BRANICK

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

A. My name is Karen A. Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company in the position of Director - Electric Regulatory Affairs.

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

A. I received a Bachelor of Science Degree in Chemical Engineering and Chemistry from the University of Pittsburgh, Pittsburgh, Pennsylvania in 1986. In 1987 I was employed as a chemist for Florida Power & Light Company (FPL). In 1990, I became a performance engineer; in 1991 a laboratory supervisor; and in 1992 an operations supervisor for FPL. My career at Tampa Electric began in 1992 in the Production Department. My responsibilities included insurance of proper boiler chemistry and chemical engineering support during normal operations and maintenance outages. I led projects related to alternate fuel test burns and waste water management. In 1994, I transferred to the Bulk Power & Market Development Department where I managed the customer accounts of approximately 30 of Tampa Electric's large industrial customers. I also participated in developing proposals for long term off-system sales of wholesale power. In October 1996, I was promoted to Manager-Energy Issues in the Regulatory and Business Strategy Department. In June of 1997 I was promoted to my current position of Director. My present responsibilities include the areas of fuel adjustment filings, capacity costs recovery filings, environmental cost recovery filings, pricing and rate design and issues under the Federal jurisdiction.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Commission the proposed Total Fuel and Purchased Power Cost Recovery factors, the proposed Capacity Cost Recovery factors and the billing refund credit factors for the period of October 1997 - March 1998.

Fuel and Purchased Power Cost Recovery Factors / Capacity Cost Recovery Clause

Q. Did you review the projected data necessary to calculate the Total Fuel and Purchased Power Cost Recovery factors for the period October 1997 - March 1998?

A. Yes I have.

Q. Do you wish to sponsor an exhibit consisting of Schedules H-1 (October - March, 1994 through 1997) and Schedules E-1 through E-10 (October 1997 - March 1998)?

A. Yes. Also contained in this exhibit are Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the prior period April 1997 - September 1997. These schedules are furnished as back-up for the projected true-up for this period and consist of two actual months and four projected months.

(Have identified as Exhibit No. 34 (KAB-2), Fuel Projection.)

Q. Does Schedule E-1 of Exhibit No. 34 (KAB-2), Fuel Projection, show the proper value for the Total Fuel and Purchased Power Cost Recovery Clause as projected for the period October 1997 - March 1998?

A. Yes.

Q. What is the proper value of the fuel adjustment for the new period?

A. The proper value for the new period is 2.304 cents per kwh before the application of the factors that adjust for variations in line losses.

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

A. The GPIF and True-up factors are provided on Schedule E-1C. We propose that a GPIF reward of $96,660 be included in the projection period. The True-up amount for the April 1997 - September 1997 period is an overrecovery of $6,736,674. This overrecovery is comprised of a final True-up overrecovery amount of $1,926,965 for the October 1996 - March 1997 period and an estimated overrecovery in the amount of $4,809,709 for the April 1997 - September 1997 period.

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

A. Schedule E-1D presents the company's on-peak and off-peak fuel charge factors for the October 1997 - March 1998 period.

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 charge factors after adjusting for variations in line losses.

Q. How will the total revenues associated with the FMPA and Lakeland long-term off system sales be treated in the fuel clause?

A. Tampa Electric appeared before the Commission on June 11, 1997 where this issue was heard in Docket No. 970171-EU; Determination of appropriate cost allocation and regulatory treatment of total revenues associated with wholesale sales to Florida Municipal Power Agency and City of Lakeland by Tampa Electric Company. The Company made a proposal to:

- Credit revenues equal to system incremental fuel to the Fuel and Purchase Power Clause
- Credit revenues equal to incremental SO allowance costs to the Environmental Cost Recovery Clause
- credit transmission revenues and revenues equal to variable operating and maintenance expense to operating revenue above the line

- and share the remaining revenues from these sales 50/50 with 50% flowing through the fuel clause, and 50% credited to operating revenues above the line.

Tampa Electric guaranteed the rate payers 50% share of these remaining revenues would be $2 million net present value to be credited to customers over two fuel adjustment periods.

The earliest expected date for the Commission to rule on the Company's proposal is August 5, 1997. Therefore, for purposes of this fuel adjustment filing, Tampa Electric has continued to flow fuel revenues from these sales through the fuel clause, and credit the remaining revenues to above the line operating revenues.

Q. Please recap the proposed Fuel and Purchased Power Cost Recovery factors for the October 1997 - March 1998 period.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)
Average Factor	2.304
RS, GS and TS	2.321
RST and GST	2.598 (on-peak)
	2.217 (off-peak)

SL-2, OL-1 and OL-3	2.274	
GSD, GSLD, and SBF	2.307	
GSDT, GSLDT, EV-X and SBFT	2.582	(on-peak)
	2.204	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.232	
IST-1, IST-3, SBIT-1, SBIT-3	2.498	(on-peak)
	2.132	(off-peak)

Q. How does Tampa Electric Company's proposed average fuel charge factor of 2.304 cents per kwh compare to the average fuel charge factor for the April 1997 - September 1997 period?

A. The proposed fuel charge factor is 0.111 cents per kwh (or $1.11 per 1000 kwh) lower than the average fuel charge factor of 2.415 cents per kwh for the April 1997 - September 1997 period.

Q. Are you also requesting Commission approval of the projected Capacity Cost Recovery factors for the Company's various rate schedules?

A. Yes.

Q. Have you prepared or caused to be prepared under your direction or supervision an exhibit which supports this request?

A. Yes. It consists of five pages identified as Exhibit No. 35 KAB-3, Capacity Cost Recovery.

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

A. Tampa Electric is requesting recovery, through the capacity cost recovery factor, of capacity payments made pursuant to cogeneration, small power production and purchased power agreements to which we are a party.

Q. Please re-cap the proposed Capacity Cost Recovery Clause factors for the October 1997 - March 1998 period.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.228
GS and TS	0.220
GSD, EV-X	0.168
GSLD and SBF	0.149
IS-1, IS-3, SBI-1, SBI-3	0.013
SL-2, OL-1 and OL-3	0.026

These factors can be seen in Exhibit No. 35 (KAB-3), page 3 of 5.

Stipulation Refund

Q. Does the current Revenue Credit Refund Factor of 0.168 cent per kWh terminate after September 1997?

A. Yes. The company is currently refunding $25 million, plus interest, over the 12-month period from October 1996 through September 1997. This refund is in accordance with the Stipulation between Tampa Electric, the Office of Public Counsel and the Florida Industrial Users Group signed March 25, 1996. This stipulation was approved in Order No. PSC-96-0670-S-EI in Docket No. 950379-E issued May 20, 1996. This revenue credit refund factor is shown as a line item on the customer's bill. This revenue credit factor will terminate after the last billing cycle for the month of September 1997. As defined in the Stipulation, any over or under collection balance ending September 1997 associated with the refund credit will be handled as a true-up component in the normal course of Tampa Electric's fuel cost recovery proceedings.

Temporary Base Rate Reduction

Q. Will Tampa Electric begin a temporary base rate decrease in October 1997?

A. Yes. On September 25, 1996, Tampa Electric, the Office of Public Counsel and the Florida Industrial Power Users Group signed a separate stipulation. This stipulation was subsequently approved in Order No. PSC-96-1300-S-EI in Docket No. 960409-EI issued October 24, 1996. As part of this Stipulation, Tampa Electric has agreed to a temporary base rate reduction in the total amount of $25 million over fifteen months beginning about October 1, 1997. The base rate reduction is to begin concurrently with the fuel adjustment period beginning about October 1, 1997. This temporary base rate reduction will be shown as a line item on the customer's bill, replacing the refund currently on the bill.

This temporary base rate decrease will be 0.130 cent per kWh on average. The factors by rate class, adjusted for line loss, are shown below. The derivation of these factors is shown in Document No. 4 of Exhibit KAB-2.

Rate Class	Credit Factor cents / kWh
Average Factor	0.130
RS, RST, GS, GST, TS	0.131
GSD, GSDT, GSLD, GSLDT, EV-X, SBF, SBFT	0.130
IS-1&3, IST-1&3, SBIT-1&3	0.126
SL, OL	0.131

Q. What is the composite effect of the above changes on a 1,000 kwh residential Customer?

A. A residential bill for 1,000 kwh will decrease $0.03 beginning October 1997. See table below.

Type of Charge	Apr. 97 thru Sept. 97	Oct. 97 thru Mar. 98
Customer	$ 8.50	$ 8.50
Energy	43.42	43.42
Conservation	1.63	1.63
Environmental	0.33	0.54
Fuel	24.32	23.21
Capacity	1.79	2.28
Deferred Revenue Plan		
Refund	(1.69)	(1.31)
FGR Tax	2.01	2.01
Total	$ 80.31	$ 80.28

Q. When should the new charges and refund go into effect?

A. They should go into effect commensurate with the first billing cycle in October 1997.

Q. Does this conclude your testimony?

A. Yes it does.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL DIRECT TESTIMONY

OF

KAREN A. BRANICK

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

A. My name is Karen A. Branick. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company in the position of Director - Electric Regulatory Affairs.

Q. Are you the same Karen A. Branick who filed direct testimony in this Docket?

A. Yes I am.

Q. What is the purpose of your Supplemental testimony?

A. The purpose of my testimony is to explain how Tampa Electric has executed energy sales and purchases on the Florida Energy Broker, and treated the margin revenues associated with these transactions both prior to and subsequent to the issuance of the "Open Access" rule promulgated by FERC. I will also explain how Tampa

Electric's current treatment of crediting transmission revenues from within its margin share to above the line operating revenue meets FERC requirements under the new Rule 888, and is consistent with past Florida Commission treatment of transmission revenues. I will also show how Tampa Electric's approach is consistent with continuing the viability of the Florida Broker system and the benefits it affords to retail customers.

Q. How does the Florida Energy Broker network function?

A. The Broker network and the associated FERC Schedule C Interchange Agreements between utilities in Florida are designed to offer the lowest price for power providing savings to the purchaser and additional revenues to the seller. The Broker works in the following manner: Sell and Buy Quotes on the Broker are to include only the incremental cost of making such sales. Specifically, this means that utilities are permitted to quote incremental fuel and any variable O&M costs in their quotes. The Sell and Buy Quotes are averaged to determine the transaction price for each matched transaction. On the Buyer's side of the transaction, the difference between the Buy Quote and the transaction price represents the buyer's savings from the transaction. On the Seller's side of the transaction, the difference between the transaction price and the Sell Quote determines the margin on the sale. Since all variable costs have been covered, this margin is considered to be an overall benefit from the sale. This Commission recognized the need to incent utilities to maximize the benefits associated with Broker transactions and allowed a sharing of this margin.

Q. How has Tampa Electric treated transmission revenues associated with broker transactions prior to Rule 888?

A. Margins from broker sales in total were shared 80/20 with 80% flowing through the fuel clause and 20% flowing to shareholders below the line. Exhibit No. 11 KAB-5 shows this in detail. This margin can be considered an overall benefit from the sale with no dollars "ear-marked" for transmission.

Q. How has Tampa Electric treated transmission revenues associated with Broker transactions since Rule 888?

A. Beginning on January 1, 1997, Tampa Electric has had to modify the treatment of the margin from broker sales. A match on the broker will not occur between Tampa Electric and a purchaser unless the sales margin is at least equivalent to Tampa Electric's transmission rate for the transaction. From the margin, revenues equal to the transmission rate are credited above the line to operating revenues. Remaining margin revenues are shared 80/20 with 80% flowing through the fuel clause to retail customers and 20% to the shareholders below the line. See Exhibit No. 11 KAB-5.

Q. Is Tampa Electric's present treatment of crediting these transmission revenues above the line a fair and reasonable response to the implementation of FERC Order 888?

A. Yes. As Mr. Kordecki has pointed out in his direct testimony, FERC has in effect, required us to treat these imputed transmission revenues from broker sales in precisely the same way as other third party transmission revenues would be treated for FERC jurisdictional transmission ratemaking purposes.

Q. What is involved in this approach?

A. Transmission is treated in rate base as a rate base asset for both the wholesale and retail jurisdictions. Provided there is prudent management of rate base and expenses by a utility, a utility is entitled to the recovery of its costs. In the case of rate based transmission assets, the recovery of costs means the recovery of revenue requirements, which include depreciation, operating expenses, returns on investment and taxes. These revenue requirements are recovered through base rates in both the retail and wholesale jurisdictions. Thus, these costs are not dealt with in the fuel or other cost recovery clauses in either the wholesale or retail jurisdictions. Therefore, revenue crediting of transmission revenues must be accomplished within the base rate part of the total rate.

Q. Is your proposal consistent with current Commission practices and in the interest of retail customers?

A. Yes. This proposed treatment is entirely consistent with the way this Commission has treated third party transmission revenues for ratemaking purposes. In past electric rate cases, the Commission has ordered utilities to revenue credit transmission revenues for retail ratemaking purposes. Most recently, for Tampa Electric this was done in its last rate case, Docket No. 920324-EI.

Tampa Electric's proposal also allows retail customers to benefit fully from transmission related revenues by crediting this amount to above the line operating revenue. This accounting treatment has the effect of both postponing the need for a rate adjustment and decreasing the resulting revenue requirement when retail rates are next adjusted on the basis of a cost of service analysis. In the case of Tampa Electric, this benefit to retail customers is even more immediate due to the effect of the ROE sharing mechanism in the October, 1996 stipulation on earnings rates which, in effect, operates as an "instant ratemaking" mechanism.

In addition, Tampa Electric's proposal gives retail rate customers the benefit above the line of revenues that would have been allocated to shareholders below the line under the pre Order 888 approach.

Q. Please elaborate on this last point.

A. Let me illustrate this point by referring to Exhibit No.11 KAB-5. In Exhibit No.11 KAB-5, I posit an economy energy transaction where seller's incremental cost is $20.00, buyer's decremental cost is $30.00 and the resulting transaction price, on a split the savings basis, is $25.00. This is the example that was used at the May 30, 1997 workshop on the treatment of transmission revenues from

Broker transactions. Both before and after the changes caused by Order 888, the net benefit to the seller associated with this transaction is a gain of $5.00.

Under the regulatory approach to this sale which Tampa Electric would have applied prior to Order 888, $4.00, or 80% of the $5.00 gain, would have been flowed to rate payers through the fuel clause and $1.00 would have been credited to shareholders below the line. Under Tampa Electric's proposed post Order 888 approach, $1.60 of the $5.00 gain, representing the imputed transmission revenues, would be credited to above the line operating revenue enuring to the benefit of retail customers as described above and as shown in Exhibit No. ll KAB-5. 80% of the remaining $3.40 benefit, or $2.72, would be credited to retail customers through the fuel clause resulting in a total benefit to retail customers of $4.32 ($1.60 + $2.72) as opposed to the $4.00 benefit which retail customers would have enjoyed under the pre Order 888 approach. The shareholders, on the other hand, are allocated only $0.68 below the line as opposed to the $1.00 which would have been allocated below the line under the pre Order 888 approach.

In effect, under Tampa Electric's proposal, the shareholders would transfer a portion of their below the line incentive to retail customers in the form of above the line operating revenue, or $0.32 in this example. Therefore, not only are retail customers held harmless under Tampa Electrics proposal, but they are actually better off.

Q. Has Rule 888 changed the way Tampa Electric treats costs associated with purchases made on the broker system?

A. No. Tampa Electric continues to recover these costs, and retail customers continue to realize the savings of a Broker purchase through the Fuel and Purchase Power Cost Recovery Clause.

Q. Does this conclude your testimony?

A. Yes it does.

Q (By Mr. Willis) Would you please summarise your testimony?

A Yes.

Good afternoon, Commissioners. I've testified in this proceeding to the issue of the appropriate treatment of transmission revenues for broker transactions since the issuance of open access rule, FERC 888 and 888-A. I'd like to summarize that testimony for you now.

Prior to Rule 888 and 888-A, no dollars from broker sales were earmarked for transmission and 100% of the margin from these sales was shared 80/20 with the customer: 80% flowing to the fuel clause and 20% below the line to shareholders.

On January 1st, 1997, certain dollars associated with broker sales are now recognized as transmission revenues as per the rule, which in effect required the utilities to begin treating themselves as third-party users of their transmission systems, and to account for them in a separate FERC subaccount. These third-party transmission dollars are contribution to fixed costs. And to be consistent with third-party transmission revenues where the Commission ordered these revenues to be retained in base rates as a credit to revenue requirements, Tampa

Electric Company seeks the approval of this Commission to credit these broker transmission revenues in the same manner: as a credit to revenue requirements and above the line operating revenue. The remaining margin would continue to be shared 80/20 between customer and company.

Commission approval of Tampa Electric's proposed treatment will give the ratepayers the benefit of all of the transmission revenues.

With regard to Staff's proposed exhibit which compares utility treatments of transmission revenues of Rule 888, we believe that the title of Line J, stockholder gain, is not appropriate for Tampa Electric. This is the case due to the general stipulation on rates and earnings under which Tampa Electric is operating, and which calls for customer and company to share above the line operating revenues. I just wanted to make that clarification. Thank you.

MR. WILLIS: Tender the witness.

CHAIRMAN JOHNSON: Mr. Childs.

MR. CHILDS: No questions.

MR. McGEE: No questions.

MR. STONE: No questions.

CHAIRMAN JOHNSON: Public Counsel.

CROSS EXAMINATION

BY MR. BURGESS:

Q Yes. You indicated -- you used the term "benefit fully" and I notice in your testimony of June 23rd, at the bottom of Page 5, you use the term "that this treatment allows the retail customers to benefit fully." What do you mean benefit fully? What is the notion of that? As opposed to the 80/20? Is it something they are getting a better deal on?

A Now that the transmission revenues -- now that transmission revenues are identified as separate revenues, 100% of those revenues are retained above the line. So at the next rate proceeding, when rates are reduced by that amount -- or revenue requirements are reduced by that amount, excuse me, that benefit is to the ratepayers.

Q Couldn't you just as well allow them to benefit fully by passing it through 100% as a specific segregated transmission amount through the fuel adjustment clause?

A I think one other possibility when I was writing this was that they would continue to be separated 80/20 with the rest of the margin. And in this respect 100% would go to them via reduction in revenue requirement.

Q Why would they need to if you separated them out as transmission and simply credited as transmission revenues and credited it through the fuel adjustment?

A I'm sorry, why would they need to --

Q Why would you need to do a 80/20 split?

A My point was that if the margin were split 80/20, then 20% of the transmission revenues would have gone below the line and the customer would not have received 100% of the benefits of transmission revenues.

Q And my question is simply can't you do the same thing in the fuel adjustment clause? Just consider it one of the costs that gets passed through directly as opposed to the -- as opposed to a margin, which is separated 80/20?

A And I would have to refer back to when Mr. Howell was explaining the inequity problem with passing back 100% through the retail fuel clause.

Q In this case isn't it -- let me ask you this: You indicate that -- on the next page that this is going to go back, and you've also mentioned this is going to go back in instant ratemaking because of an agreement. Are you talking about if earnings go above a certain level there's an agreement to refund an amount back?

A That's correct.

Q But it's got to go above a certain level before there's a sharing with the customers; is that correct?

A That's correct.

Q So if it doesn't go above that level, then there is no sharing of this with the customers; is that correct?

A There's no sharing of them -- under that stipulation as an instant ratemaking share.

Q And even when there is, I thought there were certain thresholds. The first threshold is the 60/40 split?

A That is correct.

Q So then the customers would get 60% of this full benefit?

A There would be a sharing of the operating revenues.

Q And even that amount is deferred until the following year, isn't it, and considered part of the earnings of the following year?

A Yes. And I would have to say I'm not an expert on the stipulation.

Q Do you know whether there's also an

additional 60/40 split in the following year?

A The following year being which year?

Q Being the second year after there are these full benefits that are shared by customers to the above the line treatment in base rates?

A We share through 1999 and that's what I know.

Q But if the customers are receiving 60% one year and then that's deferred to the next year, which again contains a 60% threshold, then you're down to 36% of the sharing for the benefit of the customers? (Pause)

You've indicated that you aren't that familiar with the stipulation --

A That's correct.

Q -- so I'll withdraw that question.

MR. BURGESS: That's all I have, Commissioners.

MS. KAUFMAN: I have no questions.

CHAIRMAN JOHNSON: Staff.

MS. PAUGH: Staff has an exhibit we'd like to distribute, please. While Tom is doing that, I can ask the question.

CROSS EXAMINATION

BY MS. PAUGH:

Q Is TECO a net purchaser or net seller on the broker system, Ms. Branick?

A A net seller.

MS. PAUGH: We would request that this exhibit be marked for identification.

CHAIRMAN JOHNSON: It will be marked as Exhibit 12 and identified "Economy Sale by TECO."

(Exhibit 12 marked for identification.)

Q **(By Ms. Paugh)** This document is based on your KAB-5. However, it revises your $1.60 transmission charge to a $3 transmission charge for purposes of consistency with the other utilities' testimony and for clarity of comparison by this panel. Do you want to take a moment to review the document? (Pause)

A It's correct.

Q Does the price of this transaction remain the same as before FERC Order 888?

A You mean the same before as after?

Q Yes.

A Yes.

Q Is the transmission component an incremental cost of this sale?

A No.

Q Are there any new costs as a result of FERC Order 888?

A That's a question? Excuse me, could you ask that again?

Q Are there any new costs as a result of FERC Order 888?

A No.

Q Does Tampa Electric intend to bill the buyer separately for the $3 transmission charge?

A No.

Q Before FERC Order 888, Tampa Electric's ratepayers would see an immediate net fuel credit of $4 when Tampa Electric made such a sale, is that correct, based on this example of Exhibit 12?

A Yes.

Q And after FERC Order 888, the immediate net fuel credit for ratepayers is reduced to $1.60; is that correct?

A Yes.

Q How would Tampa Electric propose that the buyer recover the transmission cost of this transaction?

A The buyer isn't charged a transmission charge.

Q So the buyer has no cost for transmission?

A He pays the transaction price from above.

Q Is it your testimony that if the buyer flows the transmission cost directly to the ratepayers through the fuel clause and the seller credits the transmission revenues to operating revenue -- I'll withdraw that question.

I'd like to address wheeling for a moment. Did wheeling charges affect the transaction price of a broker sale prior to FERC Order 888?

A That's my understanding, yes.

Q Broker sales are nonfirm in that they are recallable; is that correct?

A Yes.

Q Thus likewise the transmission revenues are nonfirm or volatile; is that correct?

A To the extent that a transaction is not made there would be no transmission revenues.

Q I would refer you now to Page 6, Lines 2 through 5 of your direct testimony. Will you please read that section?

A "This accounting treatment has the effect of both postponing a need for a rate adjustment and decreasing the resulting revenue requirement when retail rates are next adjusted on the basis of a cost of service analysis."

Q Is it your testimony that one of the benefits of crediting revenues above the line is a decrease in revenue requirements when retail rates are next set?

A Yes.

Q Now, suppose that TECO filed for a rate case next year. In order to capture the revenue requirement reduction due to these transmission revenues, a projection of broker sales would have to be made for the test year; is that correct?

A Yes.

Q And broker sales are difficult to project, which is why the Commission moved them from base rates into the fuel clause in order number -- I believe beneficially noticed it's 12923 in Docket 830001; is that correct?

A That's what that order says. Yes. (Pause)

Q Did wheeling rates affect gain on broker sales?

A They would affect the buyer's gain.

Q Okay. What about the seller's gain in the 80/20 split?

A No. The buyer pays the wheeling.

Q Ms. Branick, do you have a copy of the exhibit marked as No. 4 with you?

A That's the comparison of the utilities?

Q No. That's the Florida Power Corporation generated document entitled "Nondirectly Interconnected Utilities Example."

A Yes.

Q Do you agree where it says fuel adjustment clause is credited 80% of gain with the calculation that $5 times .8 equals $4?

A Yes.

MS. PAUGH: We have no further questions.

CHAIRMAN JOHNSON: Commissioners? Redirect?

REDIRECT EXAMINATION

BY MR. WILLIS:

Q Ms. Branick, is the reason for treating transmission revenues above the line that the transmission revenues are a contribution to fixed costs?

A That's correct.

Q Could you explain that, please?

A At the next time that rates are determined for retail customers, these revenues would be treated as a reduction in the revenue requirement for those rates.

Q Isn't it true that Order 888 created the situation where transmission revenues had to be identified?

A That is correct.

Q Okay. Now, with respect to a rate proceeding, both before and after Order 888, wouldn't it be true that the company would have to project whatever transmission revenues it may receive in the test period?

A It would, yes.

MR. WILLIS: Thank you. No further questions.

CHAIRMAN JOHNSON: Exhibits.

MS. PAUGH: We would request Exhibit 12 be moved into the record.

MR. WILLIS: Move 11.

CHAIRMAN JOHNSON: 11 and 12 will be admitted without objection.

(Exhibits 11 and 12 received in evidence.)

CHAIRMAN JOHNSON: Thank you, ma'am.

(Witness Branick excused.)

MS. PAUGH: Staff also requests that Exhibit 3 be moved into the record.

CHAIRMAN JOHNSON: Is there any objection to Exhibit 3?

MR. STONE: I continue my objection to

Exhibit 3. There's information that this is compiled that is attributed to Gulf. There were no questions asked of Gulf's witnesses. There's no person that's before the Commission to explain how this was compiled and how this information was derived, and, therefore, it is not appropriate to be admitted as an exhibit. There was no sponsor.

MR. WILLIS: Tampa Electric also objects to it. In addition to the grounds stated by Mr. Stone, the -- with particular, the Line J, which describes certain amounts as stockholder gain between rate cases is incorrect, it's mislabled, and distorts exactly what those numbers are or purport to be. And for that reason it -- we agree that it should not be admitted into evidence.

CHAIRMAN JOHNSON: Staff.

MS. PAUGH: This exhibit was generated based on the testimony of the parties. It's correct. It is based on their testimony and exhibits.

CHAIRMAN JOHNSON: It's based upon testimony that's been admitted and exhibits?

MS. PAUGH: Yes. The exhibits attached to the testimony.

MR. WILLIS: That's the whole point. We did not testify to what's on this exhibit. And with particularity, Line J, which is labeled "Stockholder Gain Between Rate Cases," when we know specifically through the basis of the testimony of both Gulf's witness and Tampa Electric is witness that that's incorrect.

CHAIRMAN JOHNSON: Staff.

MS. PAUGH: Staff maintains that it's correct.

CHAIRMAN JOHNSON: Staff, the parties are raising some good points with respect to the information. If there's no one that testified as to like Line J, nor have we been able to verify the information that's in here through a witness.

MS. PAUGH: Madam Chairman, if I could make this a bit easier. We would agree to omit Line J from the exhibit and submit it as a revised exhibit.

CHAIRMAN JOHNSON: Gulf, what other information --

MR. STONE: If I may take take moment to review it.

CHAIRMAN JOHNSON: If TECO could do the same.

MR. WILLIS: That would be fine with that change. (Pause)

MR. STONE: With the omission of Line J we would have no further objection.

CHAIRMAN JOHNSON: Okay. Then Staff will be submitting a revised Exhibit 3 that will be basically the same but will not include J.

MR. STONE: Is it also my understanding they would omit the column with regard to Florida Power Corp after 7-9-96 that was previously omitted?

MS. PAUGH: That is correct, Madam Chairman. We will send copies of the revised exhibits to all of the parties as well.

CHAIRMAN JOHNSON: Okay. How do I do this procedurely? I haven't seen the document either, but could I go ahead and admitted it as revised, or it will be admitted if none of the parties object.

MR. WILLIS: It's like a late-filed exhibit.

MS. PAUGH: Let's make it a late-filed exhibit.

CHAIRMAN JOHNSON: Okay. And we'll just identify it as Late-filed Exhibit 13, and we'll show 3 withdrawn. And it will be Revised Summary of Proposed Regulatory Treatment of Broker Sales.

(Late-Filed Exhibit 13 identified.)

(Exhibit 3 withdrawn.)

CHAIRMAN JOHNSON: Any other matters?

MS. PAUGH: We need to identify the

remainder of the exhibits for issues that were stipulated.

CHAIRMAN JOHNSON: Okay.

MS. PAUGH: Shall I take the lead?

CHAIRMAN JOHNSON: Yes, ma'am.

MS. PAUGH: JS-1 can be identified as Exhibit 14. JS-2,15; JS-3, 16; KAW-1 --

CHAIRMAN JOHNSON: Those have already been --

MS. PAUGH: Has already been identified as Exhibit 1, KHW-2 has already been identified as Exhibit 2. DBZ--1 will be Exhibit 17. DBZ-2, 18. RS-1, 19. RS-2, 20. RS-3, 21. KMD-1, 22. KMD-2, 23. GMB-3, 24. KMD-3, 25. MV-1, 26. MV-2, 27. MF0-1 --

CHAIRMAN JOHNSON: Hold on one second. We have a MV-1 and MV-2, don't we?

MR. STONE: I believe they were 5 and 6 when they were earlier.

MS. PAUGH: Oh, those have been entered. I'm sorry, I did not make a note of it.

MS. PAUGH: Dropping back, MV- 2 would become -- I'm sorry MF0-1 is 26; is that correct?

MS. PAUGH: Lawyers can't add or subtract. MF0-2 is 27. MWH-1 is 28. MWH 2 is 29.

CHAIRMAN JOHNSON: No. That would be 8. MWH-2 will be 8. It's already been admitted.

MS. PAUGH: I apologize. SDC-1, Exhibit 29. SDC-2, 30. GDF-1, 31. GDF-2, 32, KAB-1,33; is that correct?

CHAIRMAN JOHNSON: Yes. KAB-2, 34. KAB-5, 35 -- KAB-3, 35. KAB-4, 36.

MR. WILLIS: Let me just point out that that 4 was -- I think the title in the Prehearing Order is incorrect. It should be "Deferred Revenue Plan $25 million Refund, "is the title for KAB-4.

MS. PAUGH: It should read Deferred --

MR. WILLIS: "Deferred Revenue Plan 25 million Refund."

MS. PAUGH: I've made the change.

MR. WILLIS: Okay.

MS. PAUGH: KAB-5, economy sales by TECO.

CHAIRMAN JOHNSON: It's 11. That's been admitted.

MS. PAUGH: GJK-1.

CHAIRMAN JOHNSON: That was also admitted as 9.

MS. PAUGH: GAK-1 would be 37. GAK-2, 38. GAK-3, 39. CRB-1, 40. That is all of the exhibits.

CHAIRMAN JOHNSON: Okay. They've all been marked and identified. Show them all admitted without objection.

(Exhibits 14 through 40 marked for identification and received in evidence.)

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(Transcript continues in sequence in Volume 3.)