

BEFORE THE  
FLORIDA PUBLIC SERVICE COMMISSION

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In the Matter of : DOCKET NO. 990001-EI  
:  
Fuel and purchased :  
power cost recovery :  
clause and generating :  
performance incentive :  
factor. :  
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VOLUME 3

Pages 279 through 523

PROCEEDINGS: HEARING

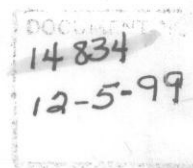
BEFORE: COMMISSIONER J. TERRY DEASON  
COMMISSIONER SUSAN F. CLARK  
COMMISSIONER E. LEON JACOBS, Jr.

DATE: Tuesday, November 23, 1999

TIME: Commenced at 9:00 a.m.

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

REPORTED BY: KIMBERLY K. BERENS, CSR, RPR  
FPSC Commission Reporter



1     **APPEARANCES:**

2                     (As heretofore noted.)

3  
4     Also Present:

5             David Wheeler, FPSC Staff

6             Elisabeth Draper, FPSC Staff

7             Tom Ballinger, FPSC Staff

8             Todd Bohrmann, FPSC Staff

9             Pat Lee, FPSC Staff

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## I N D E X

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P R O C E E D I N G S

(Hearing convened at 9:35 a.m.)

**COMMISSIONER DEASON:** Call the hearing to order. Can I have the Notice read, please.

**MR. KEATING:** Pursuant to Notice issued September 22, 1999 this time and place have been set for a hearing in Docket No. 990001-EI, Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor; Docket No. 990002-EG, Energy Conversation Cost Recovery Clause; Docket No. 990003-GU, Purchased Gas Adjustment True-up; and Docket No. 990007-EI, Environmental Cost Recovery Clause.

**COMMISSIONER DEASON:** Thank you. We are going to take appearances in just a moment. Let me ask Staff, are we going to take appearances for all the dockets at this time?

**MR. KEATING:** I think that's how we've done it.

**COMMISSIONER DEASON:** And then parties will indicate on which dockets they are appearing?

**MR. KEATING:** Yes.

**COMMISSIONER DEASON:** Very well. We'll take appearances.

**MR. BURGESS:** I'm Steve Burgess here on

1   behalf of the Public Counsel's Office representing the  
2   Citizens of the State of Florida in all the dockets  
3   before the Commission.

4           **MR. PALECKI:** Michael Palecki on behalf of  
5   City Gas Company of Florida, 3111 Mahan Drive,  
6   Tallahassee, Florida in the 002 and 003 dockets.

7           **MR. MCGEE:** James McGee on behalf of Florida  
8   Power Corporation in the 01 and 02 dockets.

9           **MS. KAUFMAN:** John McWhirter and Vicki  
10   Gordon Kaufman of the McWhirter Reeves law firm on  
11   behalf of the Florida Industrial Power Users Group in  
12   the 01, 02 and 07 dockets.

13           **MR. CHILDS:** Matthew M. Childs with the firm  
14   of Steel, Hector and Davis appearing on behalf of  
15   Florida Power & Light Company in the 01 and 07  
16   dockets.

17           **MR. STONE:** Jeffrey A. Stone and together  
18   with me is Russell A. Badders of the law firm of Beggs  
19   and Lane, Pensacola, and we're appearing in the 01, 02  
20   and 07 dockets.

21           **MR. WILLIS:** Lee L. Willis together with  
22   James D. Beasley and Kenneth R. Hart of Ausley &  
23   McMullen, P.O. Box 391, Tallahassee, Florida 32302  
24   appearing on behalf of Tampa Electric Company in the  
25   01, 02 and 07 dockets.

1           **MR. KEATING:** Cochran Keating appearing on  
2 behalf of the Commission Staff in the 01 and 03  
3 dockets.

4           **MS. JAYE:** Grace Jaye appearing on behalf of  
5 Commission Staff in the 02 and 07 dockets.

6           **COMMISSIONER DEASON:** And there are a number  
7 of other parties who have been excused from this  
8 proceeding because all issues have been stipulated; is  
9 that correct?

10          **MR. KEATING:** I believe so.

11          **COMMISSIONER DEASON:** Very well.

12                           \* \* \* \* \*

13          **COMMISSIONER DEASON:** Call the hearing to  
14 order.

15          **MR. STONE:** Thank you, Commissioner. Would  
16 Ms. Davis please take the stand.

17          **MR. KEATING:** Mr. Stone, at this point Staff  
18 had had questions for Ms. Davis unless -- if the other  
19 parties don't, at this time I think we can stipulate  
20 her testimony into the record.

21          **COMMISSIONER DEASON:** Do any of the other  
22 parties have questions for Ms. Davis? Very well.

23          **MR. STONE:** With that, Commissioner, I would  
24 ask that we insert Ms. Davis' testimony into the  
25 record as though read.

1                   **COMMISSIONER DEASON:** Somebody is smiling  
2 really large. Anyway, go ahead.

3                   **MR. STONE:** We have two sets of testimony of  
4 Ms. Davis to insert into the record. She has an  
5 April 1, 1999 set consisting of six pages and an  
6 October 1, 1999 set consisting of ten pages. Those  
7 would represent the final true-up and the projection  
8 filings.

9                   **COMMISSIONER DEASON:** And you move that  
10 testimony at this time?

11                   **MR. STONE:** Yes, I do.

12                   **COMMISSIONER DEASON:** Without objection,  
13 show then that both sets of testimony will be inserted  
14 into the record.

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## 1 GULF POWER COMPANY

2 Before the Florida Public Service Commission  
3 Prepared Direct Testimony of  
4 Terry A. Davis  
5 Docket No. 990001-EI  
6 Fuel and Purchased Power Capacity Cost Recovery  
7 Date of Filing: April 1, 1999

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

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

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

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

1 of increasing responsibility with Gulf in Accounts  
2 Payable, Financial Reporting, and Cost Accounting. In  
3 1993, I joined the Rates and Regulatory Matters area,  
4 where I participated in activities related to the cost  
5 recovery clauses, budgeting, and other regulatory  
6 functions. In 1998, I was promoted to my current  
7 position, which includes preparation and coordination of  
8 the Company's Fuel, Capacity and Environmental Cost  
9 Recovery Clause filings, administration of Gulf's retail  
10 tariff, and review of other regulatory filings submitted  
11 by the Company.

12

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

15 A. Yes, I have.

16 Counsel: We ask that Ms. Davis' Exhibit  
17 consisting of four schedules be  
18 marked as Exhibit No. 23 (TAD-1).

19

20 Q. Are you familiar with the Fuel and Purchased Power  
21 (Energy) true-up calculations for the periods of April  
22 1998 through September 1998 and October 1998 through  
23 December 1998 and the Purchased Power Capacity Cost  
24 true-up calculations for the periods of October 1997  
25 through September 1998 and October 1998 through December



1 1998 set forth in your exhibit?

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

3

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

7 A. Yes, I have.

8

9 Q. What is the amount to be refunded or collected through  
10 the fuel cost recovery factor in the period January 2000  
11 through December 2000?

12 A. A net amount to be collected of \$2,450,200 was  
13 calculated as shown on Schedule 1, page 1 of my exhibit.  
14 This includes \$2,694,132 to be collected for April 1998  
15 through September 1998 as shown on page 2 of Schedule 1  
16 and \$243,932 to be refunded for October 1998 through  
17 December 1998 as shown on page 3 of Schedule 1.

18

19 Q. How were these amounts calculated?

20 A. The \$2,694,132 was calculated by taking the difference  
21 in the estimated April 1998 through September 1998  
22 under-recovery of \$3,743,611 and the actual under-  
23 recovery of \$6,437,743, which is the sum of the Period-  
24 to-Date amounts on lines 7 and 8 shown on Schedule A-2,  
25 page 2, of the monthly filing for September 1998. The

1       \$243,932 was calculated by taking the difference in the  
2       estimated October through December 1998 over-recovery of  
3       \$456,058 and the actual over-recovery of \$699,990, which  
4       is the sum of lines 7 and 8 shown on Schedule A-2,  
5       page 2, Period-to-Date of the monthly filing for  
6       December 1998. The estimated true-up amounts for these  
7       periods were approved in Order No. PSC-98-1715-FOF-EI  
8       dated December 18, 1998. Additional details supporting  
9       the approved estimated true-up amounts are included on  
10      Schedule E1-A filed October 12, 1998.

11

12   Q.   Ms. Davis, you stated earlier that you are responsible  
13       for the Purchased Power Capacity Cost true-up  
14       calculation. Which schedules of your exhibit relate to  
15       the calculation of these factors?

16   A.   Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate  
17       to the Purchased Power Capacity Cost true-up calculation  
18       for the periods October 1997 through September 1998 and  
19       October 1998 through December 1998.

20

21   Q.   What is the amount to be refunded or collected in the  
22       period January 2000 through December 2000?

23   A.   An amount to be refunded of \$81,124 was calculated as  
24       shown in Schedule CCA-1, page 1, of my exhibit. This  
25       includes \$95,729 to be collected for October 1997

1 through September 1998 as shown on page 2 of Schedule  
2 CCA-1 and \$176,853 to be refunded for October 1998  
3 through December 1998 as shown on page 3 of Schedule  
4 CCA-1.

5

6 Q. How were these amounts calculated?

7 A. The \$95,729 was calculated by taking the difference in  
8 the estimated October 1997 through September 1998 under-  
9 recovery of \$2,467,419 and the actual under-recovery of  
10 \$2,563,148, which is the sum of lines 11 and 12 under  
11 the total column of page 1 of Schedule CCA-2. The  
12 \$176,853 was calculated by taking the difference in the  
13 estimated October through December 1998 under-recovery  
14 of \$1,237,526 and the actual under-recovery of  
15 \$1,060,673, which is the sum of lines 11 and 12 under  
16 the total column of page 2 of Schedule CCA-2. The  
17 estimated true-up amounts for these periods were  
18 approved in Order No. PSC-98-1715-FOF-EI dated  
19 December 18, 1998. Additional details supporting the  
20 approved estimated true-up amounts are included on  
21 Schedule CCE-1A filed October 12, 1998.

22

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

25 A. Schedule CCA-2 page 1 shows the calculation of the

1 actual under-recovery of purchased power capacity costs  
2 for the period October 1997 through September 1998 and  
3 Schedule CCA-2 page 2 shows the calculation of the  
4 under-recovery for the period October 1998 through  
5 December 1998. Schedule CCA-3 of my exhibit is the  
6 calculation of the interest provision on the under-  
7 recoveries. Schedule CCA-3 page 1, reflects the period  
8 October 1997 through September 1998; and Schedule CCA-3  
9 page 2, reflects the period October 1998 through  
10 December 1998. This is the same method of calculating  
11 interest that is used in the Fuel and Purchased Power  
12 (Energy) Cost Recovery Clause and the Environmental Cost  
13 Recovery Clause.

14  
15 Q. Ms. Davis, does this complete your testimony?

16 A. Yes, it does.  
17  
18  
19  
20  
21  
22  
23  
24  
25

## GULF POWER COMPANY

Before the Florida Public Service Commission  
Prepared Direct Testimony of  
Terry A. Davis  
Docket No. 990001-EI  
Fuel and Purchased Power Cost Recovery  
Date of Filing: October 1, 1999

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

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

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

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

1 Payable, Financial Reporting, and Cost Accounting. In  
2 1993, I joined the Rates and Regulatory Matters area,  
3 where I participated in activities related to the cost  
4 recovery clauses, budgeting, and other regulatory  
5 functions. In 1998, I was promoted to my current  
6 position, which includes preparation and coordination of  
7 the Company's Fuel, Capacity and Environmental Cost  
8 Recovery Clause filings, administration of Gulf's retail  
9 tariff, and review of other regulatory filings submitted  
10 by the Company.  
11

12 Q. Have you previously filed testimony before this  
13 Commission in Docket No. 990001-EI?

14 A. Yes, I have.  
15

16 Q. What is the purpose of your testimony?

17 A. The purpose of my testimony is to discuss the  
18 calculation of Gulf Power's fuel cost recovery factors  
19 for the period January 2000 through December 2000. I  
20 will also discuss the calculation of the purchased power  
21 capacity cost recovery factors for the period January  
22 2000 through December 2000.  
23  
24  
25

1 Q. Are you familiar with the Fuel and Purchased Power Cost  
2 Recovery Clause Calculation for the period of January  
3 2000 through December 2000?

4 A. Yes, these documents were prepared under my supervision.  
5

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

9 A. Yes, I have.

10 Counsel: We ask that Ms. Davis's Exhibit  
11 consisting of fourteen schedules,  
12 be marked as Exhibit No. 24 (TAD-1).  
13

14 Q. Ms. Davis, what has Gulf calculated as the fuel cost  
15 recovery true-up to be applied in the period January  
16 2000 through December 2000?

17 A. The fuel cost recovery true-up for this period is an  
18 increase of .1373¢/kwh. As shown on Schedule E-1A, this  
19 includes a final under-recovery for the April through  
20 September 1998 period of \$2,694,132, plus a final over-  
21 recovery for October through December 1998 period of  
22 \$243,932, plus the estimated under-recovery of  
23 \$11,302,259 for January through December 1999 period.  
24 The resulting under-recovery is \$13,752,459.  
25

1 Q. What has been included in this filing to reflect the  
2 GPIF reward/penalty for the period of April 1998 through  
3 December 1998?

4 A. This is shown on Line 32b of Schedule E-1 as a decrease  
5 of .0004¢/kwh, thereby penalizing Gulf by \$36,679.  
6

7 Q. Ms. Davis, what is the levelized projected fuel factor  
8 for the period January 2000 through December 2000?

9 A. Gulf has proposed a levelized fuel factor of 1.950¢/kwh.  
10 It includes projected fuel and purchased power energy  
11 expenses for January 2000 through December 2000 and  
12 projected kwh sales for the same period, as well as the  
13 true-up and GPIF amount. The levelized fuel factor has  
14 not been adjusted for line losses.  
15

16 Q. How does the levelized fuel factor for the projection  
17 period compare with the levelized fuel factor for the  
18 current period?

19 A. The projected levelized fuel factor for 2000 is .288  
20 cents/kwh more or 17.3% higher than the levelized fuel  
21 factor for 1999 upon which current fuel factors are  
22 based. This increase exceeds the threshold outlined in  
23 Order No. PSC-98-0049-FOF-EI dated January 7, 1998.  
24 Most of this increase is due to an increase in the price  
25 of net purchases and sales of energy. A much smaller



1 part of this increase is due to increased costs for  
2 fuel. Mr. Howell and Mr. Oaks will elaborate on the  
3 causes of these increases in their testimonies.

4  
5 Q. Ms. Davis, how were the line loss multipliers used on  
6 Schedule E-1E calculated?

7 A. They were calculated in accordance with procedures  
8 approved in prior filings and were based on Gulf's  
9 latest mwh Load Flow Allocators.

10

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

14 A. Gulf proposes a standard fuel factor, adjusted for line  
15 losses, of 1.974¢/kwh for Group A. Fuel factors for  
16 Groups A, B, C, and D are shown on Schedule E-1E. These  
17 factors have also been adjusted for line losses.

18

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

21 A. These were calculated based on projected loads and  
22 system lambdas for the period January 2000 through  
23 December 2000. These factors included the GPIF and  
24 true-up, and were adjusted for line losses. These time-  
25 of-use fuel factors are also shown on Schedule E-1E.

1 Q. How does the proposed fuel factor for Rate Schedule RS  
2 compare with the factor applicable to December 1999 and  
3 how would the change affect the cost of 1000 kwh on  
4 Gulf's residential rate RS?

5 A. The current fuel factor for Rate Schedule RS applicable  
6 through December 1999 is 1.682¢/kwh compared with the  
7 proposed factor of 1.974¢/kwh. For a residential  
8 customer who uses 1000 kwh in January 2000, the fuel  
9 portion of the bill would increase from \$16.82 to  
10 \$19.74.  
11

12 Q. Ms. Davis, has Gulf updated its estimates of the  
13 as-available avoided energy costs to be shown on COG1 as  
14 required by Order No. 13247 issued May 1, 1984, in  
15 Docket No. 830377-EI and Order No. 19548 issued June 21,  
16 1988, in Docket No. 880001-EI?

17 A. Yes. A tabulation of these costs is set forth in  
18 Schedule E-11 of my Exhibit TAD-1. These costs  
19 represent the estimated averages for the period from  
20 January 2000 through December 2001.  
21

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

1 A. Schedule CCE-1, including CCE-1a and CCE-1b, and  
2 Schedule CCE-2 of my exhibit relate to the calculation  
3 of the PPCC recovery factors for the period January 2000  
4 through December 2000.

5  
6 Q. Please describe Schedule CCE-1 of your exhibit.

7 A. Schedule CCE-1 shows the calculation of the amount of  
8 capacity payments to be recovered through the PPCC  
9 Recovery Clause. Mr. Howell has provided me with Gulf's  
10 projected purchased power capacity transactions under  
11 the Southern Company Intercompany Interchange Contract  
12 (IIC), Gulf's contract with Solutia, and certain market  
13 capacity transactions. Gulf's total projected capacity  
14 payments for the period January 2000 through December  
15 2000 are purchases of \$12,729,433. The jurisdictional  
16 amount is \$12,281,702. For the projection period,  
17 Gulf's requested recovery before true-up is the  
18 difference between the jurisdictional projected  
19 purchased power capacity costs and the approved  
20 adjustment for former capacity transactions embedded in  
21 current base rates. This adjustment amount was fixed in  
22 Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as  
23 an annual embedded credit of \$1,678,580, or \$1,652,000  
24 net of revenue taxes. Thus, the projected recovery  
25 amount that would be collected through the PPCC recovery

1 factors in the period January 2000 through December 2000  
2 is \$13,933,702. This amount is added to the total true-  
3 up amount to determine the total purchased power  
4 capacity transactions that would be recovered in the  
5 period.

6  
7 Q. What has Gulf calculated as the purchased power capacity  
8 factor true-up to be applied in the period January 2000  
9 through December 2000?

10 A. The true-up for this period is a decrease of \$68,182 as  
11 shown on Schedule CCE-1a. This includes an estimated  
12 under-recovery of \$12,942 for January 1999 through  
13 December 1999. It also includes a final true-up under-  
14 recovery of \$95,729 for the period of October 1997  
15 through September 1998, plus a final true-up over-  
16 recovery for the period of October through December 1998  
17 of \$176,853. The resulting over-recovery is \$68,182.

18  
19 Q. What methodology was used to allocate the capacity  
20 payments to rate class?

21 A. As required by Commission Order No. 25773 in Docket  
22 No. 910794-EQ, the revenue requirements have been  
23 allocated using the cost of service methodology used in  
24 Gulf's last full requirements rate case and approved by  
25 the Commission in Order No. 23573 issued October 3,

1 1990, in Docket No. 891345-EI. Although the capacity  
2 payments in that cost of service study were allocated to  
3 rate class using the demand allocator based on the  
4 twelve monthly coincident peaks projected for the test  
5 year, for purposes of the PPCC Recovery Clause, Gulf has  
6 allocated the net purchased power capacity costs to rate  
7 class with 12/13th on demand and 1/13th on energy. This  
8 allocation is consistent with the treatment accorded to  
9 production plant in the cost of service study used in  
10 Gulf's last rate case.

11

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

14 A. The allocation factors used in the PPCC Recovery Clause  
15 have been calculated using the 1997 load data filed with  
16 the Commission in accordance with FPSC Rule 25-6.0437.  
17 The calculations of the allocation factors are shown in  
18 columns A through I on Page 1 of Schedule CCE-2.

19

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

23 A. As shown in columns A through D on page 2 of Schedule  
24 CCE-2, the 12/13th of the jurisdictional capacity cost  
25 to be recovered is allocated to rate class based on the

1 demand allocator, with the remaining 1/13th allocated  
2 based on energy. The total revenue requirement assigned  
3 to each rate class shown in column E is then divided by  
4 that class's projected kwh sales for the twelve-month  
5 period to calculate the PPCC recovery factor. This  
6 factor would be applied to each customer's total kwh to  
7 calculate the amount to be billed each month.

8  
9 Q. What is the amount related to purchased power capacity  
10 costs recovered through this factor that will be  
11 included on a residential customer's bill for 1000 kwh?

12 A. The purchased power capacity costs recovered through the  
13 clause for a residential customer who uses 1000 kwh will  
14 be \$1.67.

15  
16 Q. When does Gulf propose to collect these new fuel charges  
17 and purchased power capacity charges?

18 A. The fuel and capacity factors will be effective  
19 beginning with the first Bill Group for January 2000 and  
20 continuing through the last Bill Group for December  
21 2000.

22  
23 Q. Ms. Davis, does this complete your testimony?

24 A. Yes, it does.

1           **MR. STONE:** She also has two exhibits. The  
2 exhibit attached to her final true-up testimony dated  
3 April 1, 1999 is marked as TAD-1. It consists of four  
4 schedules. And then her schedules attached to her  
5 projection testimony we have designated in the  
6 prehearing order as TAD-2 and it consists of 40 pages  
7 of schedules and we would ask that those be marked as  
8 exhibits or as a composite exhibit and however the  
9 Commission prefers.

10           **COMMISSIONER DEASON:** The April exhibits,  
11 TAD-1, will be identify as Exhibit 23 and TAD-2, will  
12 be identified as Exhibit 24. And you move those at  
13 this time?

14           **MR. STONE:** Yes, I do.

15           **COMMISSIONER DEASON:** Without objection.  
16 Hearing no objection, show then Exhibits 23 and 24 are  
17 admitted.

18                   (Exhibits 23 and 24 marked for  
19 identification and received in evidence.)

20           **MR. STONE:** With that we call Mr. Howell to  
21 the stand.

22           **WITNESS HOWELL:** Good morning.  
23  
24  
25

1 M.W. HOWELL

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

5 DIRECT EXAMINATION

6 BY MR. STONE:

7 Q Would you please identify yourself for the  
8 record?

9 A My name is M.W. Howell. I'm a transmission  
10 and system control manager for Gulf Power Company.

11 Q Mr. Howell, were you sworn yesterday when  
12 the witnesses were sworn?

13 A Yes.

14 Q Are you the same M.W. Howell who prefiled  
15 direct testimony dated April 1, 1999 consisting of 10  
16 pages?

17 A Yes.

18 Q Are you also the same M.W. Howell who  
19 prefiled direct testimony dated October 1, 1999,  
20 consisting of 18 pages?

21 A Yes.

22 Q If I were to ask you the questions contained  
23 in those two sets of testimony, would your answers be  
24 the same?

25 A Yes.



1           **Q**     You have no changes or corrections to those  
2 two prefiled sets of testimony?

3           **A**     No changes.

4           **MR. STONE:** I would ask that those two sets  
5 of testimony be inserted into the record at though  
6 read.

7           **COMMISSIONER DEASON:** Without objection,  
8 they shall be so inserted.

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GULF POWER COMPANY

Before the Florida Public Service Commission  
Direct Testimony of  
M. W. Howell  
Docket No. 990001-EI  
Date of Filing: April 1, 1999

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

A. My name is M. W. Howell, and my business address is One Energy Place, 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,

1       Manager of System Planning, Manager of Fuel and System  
2       Planning, and Transmission and System Control Manager.  
3       My experience with the Company has included all areas of  
4       distribution operation, maintenance, and construction;  
5       transmission operation, maintenance, and construction;  
6       relaying and protection of the generation, transmission,  
7       and distribution systems; planning the generation,  
8       transmission, and distribution systems; bulk power  
9       interchange administration; overall management of fuel  
10      planning and procurement; and operation of the system  
11      dispatch center.

12           I am a member of the Engineering Committees and  
13      the Operating Committees of the Southeastern Electric  
14      Reliability Council and the Florida Reliability  
15      Coordinating Council, and have served as chairman of the  
16      Generation Subcommittee of the Edison Electric Institute  
17      System Planning Committee. I have served as chairman or  
18      member of many technical committees and task forces  
19      within the Southern electric system, the Florida  
20      Electric Power Coordinating Group, and the North  
21      American Electric Reliability Council. These have dealt  
22      with a variety of technical issues including bulk power  
23      security, system operations, bulk power contracts,  
24      generation expansion, transmission expansion,  
25      transmission interconnection requirements, central

1 dispatch, transmission system operation, transient  
2 stability, underfrequency operation, generator  
3 underfrequency protection, and system production  
4 costing.

5  
6 Q. What is the purpose of your testimony in this  
7 proceeding?

8 A. I will summarize Gulf Power Company's purchased power  
9 recoverable costs for energy purchases and sales that  
10 were incurred during the April 1998 through September  
11 1998 recovery period and the October 1998 through  
12 December 1998 recovery period. I will then compare  
13 these actual costs to their projected levels for the  
14 periods and discuss the primary reasons for the  
15 differences.

16 I will also summarize the actual capacity expenses  
17 that were incurred during the October 1997 through  
18 September 1998 recovery period and the October 1998  
19 through December 1998 recovery period. I will compare  
20 these figures to their projected levels and discuss the  
21 reasons for the differences.

22  
23 Q. During the period April 1998 through September 1998,  
24 what was Gulf's actual purchased power recoverable cost  
25 for energy purchases and how did it compare with

1 the projected amount?

2 A. Gulf's actual total purchased power recoverable cost for  
3 energy purchases, as shown on line 12 of the September  
4 1998 Period-to-Date Schedule A-1 was \$20,786,493 for  
5 676,187,675 KWH as compared to the projected amount of  
6 \$7,424,990 for 329,410,000 KWH. The actual cost per KWH  
7 purchased was 3.0741 ¢/KWH as compared to the projected  
8 2.2540 ¢/KWH, or 36% above the projection.

9

10 Q. What were the events that influenced Gulf's purchase of  
11 energy?

12 A. During May through September of the recovery period,  
13 extremely hot weather caused Gulf's actual territorial  
14 and off-system loads, as well as the customer loads of  
15 many other utilities in the Southeast United States, to  
16 be higher than projected. Because of the unavailability  
17 of low cost energy during this hot weather period, Gulf  
18 purchased more energy at a higher unit price than was  
19 forecasted in order to meet its load obligations.

20

21 Q. During the period April 1998 through September 1998,  
22 what was Gulf's actual purchased power fuel cost for  
23 energy sales and how did it compare with the  
24 projected amount?

25 A. Gulf's actual total purchased power fuel cost for energy

1 sales, as shown on line 18 of the September 1998 Period-  
2 to-Date Schedule A-1 was \$38,837,325 for 1,771,972,679  
3 KWH as compared to the projected amount of \$26,149,800  
4 for 1,282,027,000 KWH. This resulted in a variance  
5 above budget of \$12,687,525, or 49%. The actual fuel  
6 cost per KWH sold was 2.1918 ¢/KWH as compared to  
7 2.0397 ¢/KWH, or 7% above the projection.

8  
9 Q. What were the events that influenced Gulf's sale of  
10 energy?

11 A. Gulf's energy sales were over the projection due to the  
12 hot weather that caused higher territorial and off-  
13 system loads across the Southern electric system.  
14 Because of higher demand off our system, Gulf's units  
15 were able to sell more energy at higher than projected  
16 prices during the off-peak hours of each day.

17  
18 Q. During the period October 1998 through December 1998,  
19 what was Gulf's actual purchased power recoverable cost  
20 for energy purchases and how did it compare with the  
21 projected amount?

22 A. Gulf's actual total purchased power recoverable cost for  
23 energy purchases, as shown on line 12 of the December  
24 Period-to-Date Schedule A-1 was \$4,409,083 for  
25 224,697,185 KWH as compared to the projected amount of

1       \$2,594,610 for 169,740,000 KWH. The actual cost per KWH  
2       purchased was 1.9622 ¢/KWH as compared to the projected  
3       1.5286 ¢/KWH, or 28% above the projection.  
4

5   Q. What were the events that influenced Gulf's purchase of  
6       energy during the October 1998 through December 1998  
7       recovery period?

8   A. Mild weather during this recovery period led to lower  
9       than projected territorial and off-system loads. This  
10      caused an increase in the availability of low cost pool  
11      energy that allowed Gulf to purchase more economy power  
12      through the Southern electric system (SES) power pool in  
13      order to meet its load obligations. The actual unit  
14      price for these purchases was higher than projected  
15      because unplanned maintenance outages for several low  
16      cost nuclear generating units resulted in purchases from  
17      the next highest cost system units during the October  
18      1998 through December 1998 recovery period.  
19

20   Q. During the period October 1998 through December 1998,  
21      what was Gulf's actual purchased power fuel cost for  
22      energy sales and how did it compare with the  
23      projected amount?

24   A. Gulf's actual total purchased power fuel cost for energy  
25      sales, as shown on line 18 of the December 1998 Period-

1 to-Date Schedule A-1 was \$8,133,197 for 483,438,646 KWH  
2 as compared to the projected amount of \$8,215,600 for  
3 535,211,000 KWH. This resulted in a variance of \$82,403  
4 under budget, or 1%. The actual fuel cost per KWH sold  
5 was 1.6824 ¢/KWH as compared to 1.5350 ¢/KWH, or 10%  
6 above the projection.

7  
8 Q. What were the events that influenced Gulf's sale of  
9 energy?

10 A. Gulf's energy sales were lower than projected due to  
11 lower territorial and off-system loads across the SES.  
12 Because of the availability of lower cost system  
13 resources to meet the other operating companies' load  
14 requirements, the SES required less energy from Gulf's  
15 units. Thus, Gulf sold 10% less KWH than was projected.

16  
17 Q. How are Gulf's net purchased power fuel costs affected  
18 by SES energy sales?

19 A. As a member of the SES power pool, Gulf Power  
20 participates in these sales. Gulf's generating units  
21 are economically dispatched to meet the needs of its  
22 territorial customers, the system, and off-system  
23 customers.

24 Therefore, SES energy sales provide a market for  
25 Gulf's surplus energy and generally improve unit load



1 factors. The cost of fuel used to make these sales is  
2 credited against, and therefore reduces, Gulf's fuel  
3 and purchased power costs.  
4

5 Q. During the period October 1997 through September 1998,  
6 how did Gulf's actual net purchased power capacity  
7 transactions compare with the net projected  
8 transactions?

9 A. The actual net capacity cost for the October 1997  
10 through September 1998 recovery period was \$4,685,540.  
11 My June 23, 1997 direct testimony during the August 1997  
12 hearings in Docket No. 970001-EI stated that Gulf's net  
13 projected purchased power capacity cost for the October  
14 1997 through September 1998 recovery period was  
15 \$1,841,669. However, as I discussed in my June 22, 1998  
16 direct testimony during the August 1998 hearings, Docket  
17 No. 980001-EI, this projected capacity cost was revised  
18 in Gulf's first estimated true-up for the October 1997  
19 through September 1998 recovery period to reflect  
20 capacity cost increases resulting from revised system  
21 load and capacity information used in Southern  
22 Companies' Intercompany Interchange Contract (IIC)  
23 equalization calculation, as well as revised costs  
24 related to the SES market capacity purchases. Gulf  
25 included the updated amounts for IIC costs and market

1 capacity purchases in its estimated true-up for the  
2 October 1997 through September 1998 recovery period.

3 These updates resulted in revised projected  
4 capacity costs for the October 1997 through September  
5 1998 recovery period of \$4,421,141. As mentioned  
6 previously, the actual net capacity cost for the October  
7 1997 through September 1998 recovery period was  
8 \$4,685,540. The variance between the actual net  
9 capacity cost and the capacity cost contained in the  
10 estimated true-up for October 1997 through September  
11 1998 is \$264,399, or only 6% higher. This slightly  
12 higher cost was due to a slight increase in available  
13 system capacity as opposed to what was projected.

14  
15 Q. Did Gulf Power Company participate in any other capacity  
16 transactions that materially impacted its recoverable  
17 capacity costs during the October 1997 through September  
18 1998 recovery period?

19 A. No.

20  
21 Q. During the period October 1998 through December 1998,  
22 how did Gulf's actual net purchased power capacity  
23 transactions compare with the net projected  
24 transactions?

25 A. My direct testimony during the August 1998 hearings in

1 Docket No. 980001-EI stated that Gulf's net projected  
2 purchased power capacity cost for the October 1998  
3 through December 1998 recovery period was \$818,888. The  
4 actual net capacity cost for the October 1998 through  
5 December 1998 recovery period was \$815,895. This slight  
6 decrease in cost of \$2,993 is less than 1% below our  
7 projection for the recovery.  
8

9 Q. Does this conclude your testimony?

10 A. Yes.  
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GULF POWER COMPANY

Before the Florida Public Service Commission  
Direct Testimony of

M. W. Howell

Docket No. 990001-EI

Date of Filing: October 1, 1999

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

A. My name is M. W. Howell, and my business address is One Energy Place, 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, need determination, 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,

1       Manager of System Planning, Manager of Fuel and System  
2       Planning, and Transmission and System Control Manager.  
3       My experience with the Company has included all areas of  
4       distribution operation, maintenance, and construction;  
5       transmission operation, maintenance, and construction;  
6       relaying and protection of the generation, transmission,  
7       and distribution systems; planning the generation,  
8       transmission, and distribution systems; bulk power  
9       interchange administration; overall management of fuel  
10      planning and procurement; and operation of the system  
11      dispatch center.

12               I am a member of the Engineering Committees and  
13      the Operating Committees of the Southeastern Electric  
14      Reliability Council and the Florida Reliability  
15      Coordinating Council, and have served as chairman of the  
16      Generation Subcommittee of the Edison Electric Institute  
17      System Planning Committee. I have served as chairman or  
18      member of many technical committees and task forces  
19      within the Southern electric system, the Florida  
20      Electric Power Coordinating Group, and the North  
21      American Electric Reliability Council. These have dealt  
22      with a variety of technical issues including bulk power  
23      security, system operations, bulk power contracts,  
24      generation expansion, transmission expansion,  
25      transmission interconnection requirements, central

1 dispatch, transmission system operation, transient  
2 stability, underfrequency operation, generator  
3 underfrequency protection, and system production  
4 costing.  
5

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

8 A. The purpose of my testimony is to support Gulf Power  
9 Company's (Gulf) projection of purchased power  
10 recoverable costs for energy purchases and sales for the  
11 period January 2000 - December 2000 and Gulf's  
12 projection of purchased power capacity costs for the  
13 January 2000 - December 2000 recovery period. Also, I  
14 will support Gulf's revised capacity cost projection for  
15 the January 1999 - December 1999 recovery period that  
16 has occurred since the Commission issued Order No.PSC-  
17 99-1606-PCO-EI in this docket. Finally, I will address  
18 the issues raised by the Commission Staff concerning the  
19 regulatory treatment for revenues from non-separated  
20 wholesale sales and the elimination of the 20 percent  
21 shareholder incentive for certain non-separated  
22 wholesale sales.  
23  
24  
25

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

3 A. Yes. I have one exhibit to which I will refer. This  
4 exhibit was prepared under my supervision and direction.

5 Counsel: We ask that Mr. Howell's Exhibit  
6 MWH-1 be marked for identification  
7 as Exhibit 25 (MWH-1).  
8  
9

10 Q. What is Gulf's projected purchased power recoverable  
11 cost for energy purchases for the January 2000 -  
12 December 2000 recovery period?

13 A. Gulf's projected recoverable cost for energy purchases,  
14 shown on line 12 of Schedule E-1 of the fuel filing, is  
15 \$31,622,732. These purchases result from Gulf's  
16 participation in the coordinated operation of the  
17 Southern electric system (SES) power pool, as well as  
18 the Solutia and market power purchases. This amount is  
19 used by Ms. Davis as an input in the calculation of the  
20 fuel and purchased power cost adjustment factor.  
21

22 Q. What is Gulf's projected purchased power fuel cost for  
23 energy sales for the January 2000 - December 2000  
24 recovery period?

25 A. The projected fuel cost for energy sales, shown on line

1 18 of Schedule E-1, is \$ 43,892,000. These sales also  
2 result from Gulf's participation in the coordinated  
3 operation of the SES power pool. This amount is used by  
4 Ms. Davis as an input in the calculation of the fuel and  
5 purchased power cost adjustment factor. As shown on  
6 Schedule E-1 of Ms. Davis' testimony, the overall fuel  
7 and purchased power cost adjustment factor is 1.950  
8 ¢/KWH. This represents a 17.3% increase over the 1999  
9 recovery period fuel cost adjustment factor.

10

11 Q. What impact have Gulf's net energy purchases had on the  
12 purchased power cost adjustment factor for the January-  
13 December 2000 recovery period?

14 A. The higher cost of Gulf's net energy purchases account  
15 for a significant amount of the increase in the  
16 projected factor. The net energy cost for the current  
17 recovery period has risen primarily due to the  
18 substantial increase in the energy cost of market power  
19 purchases experienced by Gulf and all utilities buying  
20 from the market since the summer of 1999. The actual  
21 cost of these market purchases during the January 1999-  
22 December 1999 recovery period has caused Gulf's true-up  
23 cost for the current recovery period to increase. In  
24 addition, the overall adjustment factor has risen due to  
25 Gulf's increased market power purchase cost projection



1 for the January-December 2000 recovery period.

2

3 Q. What information is contained in your exhibit?

4 A. My exhibit lists the long-term power contracts that are  
5 included for capacity cost recovery, their associated  
6 megawatt amounts, the resulting capacity dollar amounts,  
7 and the cost of market capacity purchases.

8

9 Q. Which power contracts produce capacity transactions that  
10 are recovered through Gulf's purchased power capacity  
11 cost adjustment factor?

12 A. Two power contracts that produce recoverable capacity  
13 transactions through Gulf's purchased power capacity  
14 adjustment factor are the SES Intercompany Interchange  
15 Contract (IIC) and Gulf's cogeneration capacity purchase  
16 contract with Solutia, Inc. (Solutia). The Commission  
17 has authorized the Company to include capacity  
18 transactions under the IIC for recovery through the  
19 purchased power capacity cost adjustment factor. Gulf  
20 will continue to have IIC capacity transactions during  
21 the January 2000 - December 2000 recovery period. The  
22 energy transactions under this contract for this  
23 recovery period are handled for cost recovery purposes  
24 through the fuel cost adjustment factor.

25 The Gulf Power/Solutia cogeneration capacity

1 contract enables Gulf to purchase 19 megawatts of firm  
2 capacity until June 1, 2005. Gulf has included these  
3 costs for recovery during the January 2000 - December  
4 2000 recovery period. The energy transactions under  
5 this contract have also been approved by the Commission  
6 for recovery, and these costs are handled for cost  
7 recovery purposes through the fuel cost adjustment  
8 factor.

9  
10 Q. Are there any other arrangements that produce capacity  
11 transactions that are recovered through Gulf's purchased  
12 power capacity cost adjustment factor?

13 A. Yes. Gulf and other SES operating companies have  
14 purchased market capacity for 2000, and these purchases  
15 will continue through May 2002. Gulf will have monthly  
16 costs associated with these market purchases for the  
17 January 2000 - December 2000 recovery period. Again,  
18 the energy transactions related to these purchases are  
19 handled for cost recovery purposes through the fuel cost  
20 adjustment factor.

21  
22 Q. Has the SES made any changes to the IIC that were used  
23 in the most recent recovery factor adjustment  
24 proceedings?

25 A. Yes. On November 2, 1998 the SES filed IIC Amendment

1 No. 10. The purpose of this amendment is to improve the  
2 methodology for determining generating unit capability  
3 ratings as defined in the IIC's Periodic Rate  
4 Computation Manual. Because the effective date for  
5 implementation of this amendment is January 1, 1999, the  
6 SES November 1, 1998 IIC informational filing with the  
7 FERC has been updated in 1999 to reflect 1999 capacity  
8 resource amounts used for the IIC capacity equalization  
9 calculation to determine the capacity transactions and  
10 costs for each operating company. These updates are  
11 reflected in the projection of IIC capacity transactions  
12 among the SES operating companies for the January 2000 -  
13 December 2000 recovery period.

14  
15 Q. What are Gulf's IIC capacity transactions that are  
16 projected for the January 2000 - December 2000 recovery  
17 period?

18 A. As shown on my Exhibit MWH-1, capacity transactions  
19 under the IIC vary during each month of the recovery  
20 period. IIC capacity purchases in the amount of  
21 \$1,450,690 are projected for the period. IIC capacity  
22 sales during the same period are projected to be  
23 \$2,492,130. Therefore, the Company's net capacity  
24 transactions under the IIC for the period are net sales  
25 amounting to \$1,041,440.

1 Q. What is the cost of Gulf's capacity purchase from  
2 Solutia that is projected for the January 2000 -  
3 December 2000 recovery period?

4 A. As shown on my Exhibit MWH-1, Gulf is projected to pay  
5 \$746,424, or \$62,202 per month, to Solutia for the firm  
6 capacity purchase made pursuant to the Commission  
7 approved contract.

8

9 Q. What is the cost of Gulf's market capacity purchases  
10 that is projected for the January 2000 - December 2000  
11 recovery period?

12 A. As shown on my Exhibit MWH-1, Gulf is projected to pay a  
13 total of \$13,024,449 for the committed market capacity  
14 purchases. Capacity in varying amounts will be  
15 purchased during the months of January through December  
16 of 2000. The individual suppliers and megawatt amounts  
17 are not shown, since this is highly sensitive and  
18 confidential information. Public availability of this  
19 information would seriously undermine our competitive  
20 position and cause our customers increased cost.

21

22 Q. What are Gulf's total projected net capacity  
23 transactions for the January 2000 - December 2000  
24 recovery period?

25 A. As shown on my Exhibit MWH-1, the net sales under the

1 IIC, the Solutia contract purchases, and the committed  
2 market capacity purchases will result in a projected net  
3 capacity cost of \$12,729,433. This figure is used by  
4 Ms. Davis as an input into the calculation of the total  
5 capacity transactions to be recovered through the  
6 purchased power capacity cost adjustment factor for this  
7 annual recovery period. As shown on Schedule CCE-2 of  
8 Ms. Davis' testimony, the purchased power capacity cost  
9 adjustment factor is 0.141 ¢/KWH. This represents a  
10 38.2% increase over the 1999 recovery period cost  
11 adjustment factor.  
12

13 Q. Please explain the reasons for the increase in Gulf's  
14 purchased power capacity cost adjustment factor for the  
15 January 2000 - December 2000 recovery period.

16 A. The higher cost of additional short-term purchases  
17 needed to meet Gulf's growing customer load is primarily  
18 responsible for the increase in the projected capacity  
19 cost adjustment factor. Gulf must continue to purchase  
20 short-term capacity to ensure adequate reserves for its  
21 customers' needs until Gulf's planned combined cycle,  
22 Smith Unit No. 3, comes on-line in June 2002. When  
23 Gulf's Smith Unit 3 is completed in 2002, the need for  
24 short-term market capacity purchases will be eliminated  
25 based on today's forecast.

1 Q. Please describe Gulf's short-term capacity purchase  
2 strategy.

3 A. Since April 1996, Gulf's short-term capacity supply  
4 strategy, as indicated in its Ten-Year Site Plan  
5 process, has been one of acquiring capacity through  
6 market purchases. Gulf and the SES are committed to  
7 obtaining the best value for capacity purchases that the  
8 market can provide. Past efforts made by SES to obtain  
9 this type market capacity have been very beneficial to  
10 Gulf and its customers, as relatively cheap short-term  
11 capacity helped meet the extremely high demands  
12 experienced in the summers of 1998 and 1999. Once again  
13 for 2000, Gulf and the SES have pursued the same  
14 strategy and have gone to the short-term capacity market  
15 to supplement owned capacity resources in order to  
16 ensure its territorial customers will have an adequate  
17 and reliable supply of electricity.

18 As I stated earlier, Gulf's customers have enjoyed  
19 significant savings in past years because of our ability  
20 to buy relatively inexpensive market capacity for their  
21 needs. The market has reacted quickly to a temporary  
22 shortfall of short-term capacity by significantly  
23 raising the price of such capacity. Gulf has been able  
24 to secure a two year (June 2000-May 2002) contract for  
25 most of its unmet needs. The capacity price is in line



1 with the market, and the associated energy price is at a  
2 significant savings over what is available elsewhere.

3

4 Q. What changes in Gulf's capacity purchases and/or sales  
5 do you presently foresee for the years beyond 2000?

6 A. Since the majority of our unmet capacity needs will be  
7 supplied by this new two year contract until Smith Unit  
8 No. 3 comes on-line in 2002, purchased power costs for  
9 2001 would be expected to be in the same vicinity as  
10 those projected for 2000. By summer 2002, Gulf will  
11 have surplus capacity, and will be in a selling mode, so  
12 we would expect net capacity sales, rather than  
13 purchases, for 2002.

14

15 Q. On July 6, 1999, Gulf notified the Commission that  
16 Gulf's actual capacity costs for the recovery period  
17 ending December 31, 1999 would be at least ten percent  
18 greater than projected capacity costs. Please discuss  
19 the reasons for making this notification.

20 A. This notification, acknowledged by the Commission on  
21 August 16, 1999 in Order No.PSC-99-1606-PCO-EI, revealed  
22 that actual data for January 1999 through May 1999 and  
23 revised data for June 1999 through December 1999 had  
24 caused Gulf's estimated capacity cost for the January  
25 1999-December 1999 recovery period to increase from

1       \$7,007,984, as projected in Gulf's October 12, 1998  
2       filing, to \$9,369,621. The anticipated increase in cost  
3       was a result of additional market capacity purchases  
4       made by Gulf and the SES to meet load requirements for  
5       the months of June 1999 through September 1999 and  
6       revised data used in the IIC capacity cost calculation  
7       for June 1999 through December 1999 of the recovery  
8       period.

9               Gulf's additional market capacity purchases  
10       resulted from Gulf's need for short-term market capacity  
11       for the 1999 summer months, June through September. At  
12       the time of its October 12, 1998 projection filing, Gulf  
13       projected market capacity purchases for the summer of  
14       1999 to be \$1,593,516. With the addition of summer 1999  
15       market capacity purchases, this projection increased to  
16       \$3,948,590.

17              Gulf's increased IIC capacity purchase cost  
18       projection resulted from updated SES owned capacity  
19       resources, DSO capacity, load forecasts, and generating  
20       unit availability rates that were contained in the  
21       latest SES budget for 1999. At the time of the  
22       Company's October 1998 projection filing, Gulf projected  
23       its net IIC capacity costs for June 1999 through  
24       December 1999 of the recovery period were \$315,406.  
25       Gulf updated this projection to show that its net IIC



1 capacity costs for June 1999 through December 1999 of  
2 the recovery period would be \$485,013.

3

4 Q. Has Gulf revised its capacity cost projections for the  
5 January 1999 - December 1999 recovery period since it  
6 notified the Commission on July 6, 1999 that Gulf's  
7 actual capacity cost for the recovery period ending  
8 December 31, 1999 would be greater than its projected  
9 capacity cost?

10 A. Yes. Since Gulf's July 6, 1999 filing, Gulf has  
11 obtained actual capacity cost data for June 1999 through  
12 August 1999 that has changed its estimated capacity cost  
13 for the January 1999-December 1999 recovery period from  
14 \$9,369,621 projected in July to its current estimate of  
15 \$6,907,824.

16

17 Q. Please explain the reasons for this decrease in the  
18 estimated capacity cost.

19 A. Gulf's latest January 1999-December 1999 capacity cost  
20 projection incorporates actual June 1999-August 1999  
21 costs for both Gulf's market capacity purchases and  
22 Gulf's net IIC capacity purchases that are lower than  
23 those contained in Gulf's July 6 filing. The lower cost  
24 related to Gulf's market capacity purchases result from  
25 reduced July 1999 capacity payments by Gulf to two

1 market capacity suppliers according to provisions  
2 contained in the related contracts. The provisions  
3 specify this reduced capacity payment when the selling  
4 parties do not deliver scheduled capacity at the  
5 specified amounts. For several days during July, both  
6 parties did not deliver capacity scheduled by the SES.  
7 Also, in August 1999, Gulf received market capacity  
8 revenue related to the Georgia Power Company and  
9 Oglethorpe Power Corporation Short-term Non-firm Sales  
10 contract due to a re-allocation of June 1999 through  
11 August 1999 revenues to all five SES operating  
12 companies. Overall, Gulf's actual June 1999-August 1999  
13 market capacity purchase cost was \$1,457,720 lower than  
14 the cost projected in Gulf's July 6, 1999 notification  
15 to the Commission.

16 Gulf's actual IIC net capacity purchases for June  
17 1999 through August 1999 were lower than projected  
18 because of Gulf's higher owned capacity as compared to  
19 other SES operating companies' owned capacity. Gulf's  
20 higher owned capacity reflects the previously discussed  
21 purchase of additional summer 1999 market capacity in  
22 1999. Overall, Gulf's actual June 1999-August 1999 IIC  
23 net capacity purchase cost was \$1,004,077 lower than the  
24 cost projected in Gulf's July 6, 1999 notification to  
25 the Commission.

1           When the cost reductions for market capacity  
2           purchases and IIC net purchases are combined, the total  
3           net reduction in projected capacity costs for the  
4           January 1999-December 1999 recovery period is  
5           \$2,461,797. These reduced costs more than offset the  
6           July 6, 1999 projected cost increase of \$2,361,637.  
7           Therefore, Gulf's projected capacity cost for January  
8           1999-December 1999 is now \$6,907,824 instead of the  
9           \$7,007,984 as stated in Gulf's original projection  
10          filing on October 12, 1998.

11

12   Q.   What is the appropriate regulatory treatment for  
13          transmission revenue received from non-separated  
14          wholesale energy sales not made through the Energy  
15          Broker Network (EBN)?

16   A.   None of Gulf's economy sales are made through the EBN.  
17          FERC Order 888 requires transmission revenues associated  
18          with the sale of energy to be recorded in FERC Account  
19          No. 447. FERC also requires transmission and ancillary  
20          charges to be recorded separately. Gulf credits these  
21          amounts to its customers through the fuel clause.

22   Q.   What is the appropriate regulatory treatment for  
23          generation-related gain on non-separated wholesale  
24          energy sales not made through the EBN?

25   A.   None of Gulf's economy energy sales are made through the

1 EBN. The profit on all of Gulf's economy energy sales  
2 is split 80% to the customer and 20% to the stockholder.  
3 The 80% gain is recorded as a credit in FERC Account No.  
4 555, Recoverable Purchase Power Expense, and passed  
5 through to the customer as a reduction to expenses for  
6 purchased power in the fuel clause.

7  
8 Q. Should the Commission eliminate the 20 percent  
9 shareholder incentive set forth in Order No. 12923,  
10 issued January 24, 1984, in Docket No. 830001-EU-B?

11 A. No. Ratepayers of a net purchasing utility benefit from  
12 a vibrant economy energy market where selling utilities  
13 have both direct and indirect incentives to satisfy the  
14 market's demand for off-system economy energy. The  
15 Commission should not take any action to remove or  
16 reduce the existing direct incentives to utilities for  
17 participating in this market. If reduced amounts of  
18 lower cost economy energy were available from sellers,  
19 the net purchasing utility would have to meet its  
20 customers' needs for energy from its own higher priced  
21 units. The purchasing utility's customers would pay a  
22 higher price for energy.

23 Should there be an elimination of the shared  
24 direct incentives associated with economy sales, a net  
25 selling utility may not continue to support the

1 administrative cost and effort to actively seek out  
2 opportunities for economy energy sales. Any decrease in  
3 the amount of economy energy sales would reduce the  
4 credit to fuel cost for ratepayers that comes from  
5 sharing the direct incentives (80%/20% split of the gain  
6 from such sales) that are currently available. By  
7 establishing the existing 20% direct shareholder  
8 incentive in Order No. 12923, issued January 24, 1984,  
9 in Docket No. 830001-EU-B, the Commission recognized the  
10 need for and overall benefit to all of our customers of  
11 increased sales of economy energy.

12

13 Q. Does this conclude your testimony?

14 A. Yes.

15

16

17

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25

1 BY MR. STONE:

2 Q Mr. Howell, you have exhibit MWH-1 attached  
3 to your projection testimony, is that correct?

4 A Yes.

5 MR. STONE: I would ask that that be  
6 assigned an exhibit number.

7 COMMISSIONER DEASON: Exhibit 25.

8 (Exhibit 25 marked for identification.)

9 MR. STONE: Thank you. Then in the interest  
10 of time we will dispense with the summary and tender  
11 Mr. Howell for cross examination.

12 COMMISSIONER DEASON: Ms. Kaufman.

13 MS. KAUFMAN: Thank you, Mr. Deason.

14 CROSS EXAMINATION

15 BY MS. KAUFMAN:

16 Q Good morning, Mr. Howell.

17 A Good morning.

18 Q I'm just going to talk to you for a moment  
19 about what we've come to finally refer to as the 80/20  
20 issue.

21 A Yes, ma'am.

22 Q Would you agree with me, Mr. Howell, that  
23 currently there is a very robust and vibrant wholesale  
24 market?

25 A I would agree that there is a robust market

1 compared to what we have in the past. I would  
2 certainly go on to say that in the future this will  
3 probably look not as robust.

4 Q But you'd agree that it's certainly more  
5 robust than it was 1984?

6 A It's more robust.

7 Q Mr. Howell, if Gulf Power had some excess  
8 energy or some excess capacity that was being paid for  
9 by its ratepayers that were not -- that was not being  
10 used at the time, is it your testimony that in the  
11 absence of an incentive to sell that power, that Gulf  
12 would not attempt to market that power on behalf of  
13 its ratepayers?

14 A No. And let me do, as I think our custom is  
15 here, we answer first and then we elaborate and we  
16 have -- as I said in my testimony, we do try to market  
17 the power that we have. Gulf, by itself, does not  
18 market or make any economy sales. Gulf goes in  
19 conjunction with the Southern Company as far as making  
20 economy transactions.

21 In the event that we do have surplus  
22 electricity for sale we would market that on the  
23 Southern Company basis. In the event that we need  
24 power we would try to purchase that on a Southern  
25 Company basis. And it often happens that it's really

1 independent of what happens on Gulf Power's system.  
2 There are times when we may not have enough generation  
3 to even serve our load, and yet, because of the  
4 pooling arrangement we have with Southern we are  
5 actually making economy sales at a time when we don't  
6 have enough generation to serve our load. So it  
7 really depends on what's happening on the Southern  
8 System and not on Gulf Power Company. And the great  
9 bulk of the time the economy transactions which we  
10 make actually come out of generating units out of  
11 state and we get our portion of the profits from  
12 those. So it's not a simple yes or no answer.

13 Q I understand and I appreciate your  
14 explanation. You would agree with me, wouldn't you --  
15 and I think you said it might have been in your direct  
16 or in your rebuttal, that utilities certainly have an  
17 incentive to keep their rates low for the ratepayers,  
18 don't they?

19 A Yes, ma'am. I believe that was primarily in  
20 my rebuttal and we do have an incentive to keep our  
21 rates low and that's why I think I tried to make clear  
22 in the testimony that certainly in the absence of an  
23 incentive, long before we had the incentive we made  
24 the best efforts we could to try to market power and  
25 benefit our customers. The Commission, though,



1 recognized that if you have an incentive it should  
2 cause you to more aggressively I think is the word  
3 used in the testimony of one of the witnesses. It  
4 should cause you to more aggressively go market those  
5 and we would certainly agree with that.

6 Q In one of your previous answers you were  
7 explaining the arrangement that Gulf has with Southern  
8 Company. So Gulf does not have its own separate  
9 marketing department?

10 A That's correct. It's a single department  
11 for the entire Southern Company.

12 Q So that if I understood what you said  
13 earlier, Southern Company is the one that's really  
14 involved in making the purchases and sales?

15 A Right. On behalf of the operating companies  
16 they take all the assets of all the operating  
17 companies, all the generation available, and first  
18 call on all those resources for the customer load. In  
19 the event there is capacity available that we can sell  
20 then we would sell that out of those resources and it  
21 doesn't matter if it comes out of a Gulf or a  
22 Mississippi Power or Georgia Power. It doesn't matter  
23 where it comes from. If there's generation available  
24 to be sold for a profit, then we would do that on a  
25 system basis and Southern Company Services does that

1 on behalf of all the operating companies, and all the  
2 operating companies get some share of those profits  
3 independent of which generating unit actually picked  
4 up to make the sale.

5 Q Thank you. That's all I have.

6 COMMISSIONER DEASON: Mr. Burgess.

7 MR. BURGESS: I just would like to confirm,  
8 this is not rebuttal testimony? The testimony that  
9 was entered was prepared?

10 WITNESS HOWELL: That's right, just my  
11 direct. But she asked that and I think it probably  
12 bridged in there.

13 MR. BURGESS: I understand.

14 WITNESS HOWELL: My rebuttal will come  
15 later.

16 MR. BURGESS: I have no questions.

17 COMMISSIONER DEASON: Staff.

18 CROSS EXAMINATION

19 BY MR. KEATING:

20 Q Does Southern's other affiliates in Alabama  
21 and Georgia, do you know if they're allowed to keep  
22 and incentive share of the profits from economy sales?

23 A Counselor, I know it varies among the  
24 companies. I don't know exactly what it is, but yes,  
25 all of them keep some share of those profits for the

1 stockholder and then the customer, you know, has some  
2 share also but I'm not sure what that split is.

3 Q How would you define economy energy?

4 A I would define economy energy as you have  
5 enough generation to serve your load -- well, let's  
6 talk about purchases and sales. If a utility has  
7 enough generation to serve its load and it has a  
8 surplus that somebody else wants to buy, it would then  
9 make that sale as an economy sale. On the contrary,  
10 if we have enough generation to serve our load but  
11 somebody else happens in that hour to have less costly  
12 generation than we do then we would purchase that.  
13 So, I think the primary driver is, you need to have  
14 enough generation to serve your load, but somebody  
15 else could generate it cheaper in that hour or be  
16 willing to sell cheaper in that hour than what you  
17 could serve your load with.

18 And, of course, when that happens, your  
19 customer -- if you're a purchaser your customer gets  
20 all the benefits of that transaction. I think the  
21 example that Mr. Wieland gave of, if you're cost is 30  
22 and you have someone who's willing to sell who as an  
23 incremental cost of 20, you'll transact at 25. Well,  
24 your customer would have had to pay the 30 to generate  
25 out of his own resources. You're able to buy it at

1 25. So he saves that full five cents or five mills  
2 and all of that goes to the customer. That's the way  
3 I would define economy.

4 Q Okay. So in the definition I think I  
5 could -- would you agree that an economy energy  
6 transaction is a short-term nonfirm transaction?

7 A Yes.

8 Q Okay. If a utility who sells economy energy  
9 should suddenly need that energy to serve its native  
10 load can it recall the economy energy?

11 A Yes. I'm not aware -- there may be. But  
12 I'm not aware of any economy transaction that is not  
13 considered nonfirm and in the event something happens  
14 a utility would recall it even if they had committed  
15 for the next hour.

16 Q Does the utility who purchases the economy  
17 energy or is that utility required to have the  
18 generation resources on hand in case the economy  
19 energy transaction is not consummated?

20 A Well, I think the answer in the old days is  
21 clearly a yes. We're moving into an area where we're  
22 not really sure. In the old days, you were suppose to  
23 quote what you're incremental cost is; what is it  
24 going to cost you in the next hour to generate. And  
25 the utility that you were dealing with was suppose to

1 quote you their decremental cost. I'm sorry. You  
2 would quote your decremental cost and their  
3 incremental.

4 And so then you're actually looking at cost  
5 base rates and you would split the savings. Today, we  
6 are really moving a lot towards market based rates and  
7 the way market based rates are working, a utility will  
8 be willing to sell at a certain rate in the market.  
9 Other utilities might be willing to buy at a certain  
10 rate in the market, and you could have utilities who  
11 don't have enough electricity to serve their  
12 customers' needs who may be buying what we call  
13 economy energy short term whatever the market price  
14 is. Was that responsive to the question?

15 Q I believe so. Yes.

16 A Okay.

17 Q Going to hand an exhibit out right now. It  
18 contains Gulf's response to Staff's first set of  
19 interrogatories, Interrogatory No. 1. And I just have  
20 a couple of quick questions for you about that when  
21 you get a chance to look at it.

22 MR. KEATING: Staff would ask that this  
23 exhibit be marked for identification.

24 COMMISSIONER DEASON: Exhibit 26.

25 (Exhibit 26 marked for identification.)

1           Q        (By Mr. Keating) Mr. Howell, so you can  
2 narrow down the area that I'm going to ask you a  
3 couple of questions about, I'm looking at your  
4 responses to Part C and D of that interrogatory. I  
5 believe that's on the last page of this handout.

6           A        Yes, I see it.

7           Q        You've got two columns?

8           A        Yes, sir.

9           Q        One labeled economy sales and one labeled  
10 external sales?

11          A        Yes, sir.

12          Q        Could you explain the difference between  
13 those two?

14          A        Both of them are what we call -- what we  
15 characterize as economy transactions. What we call  
16 economy sales are those transactions with utilities  
17 with whom we are interconnected. External sales would  
18 be economy transactions a system away and let me give  
19 an example, if I could.

20                   Let's suppose that the Southern Company is  
21 selling economy transactions to Duke. We're directly  
22 interconnected so if we sell them power or buy from  
23 them we would call that -- we would characterize it or  
24 categorize it as an economy transaction.

25                   But if we're say selling or buying with AEP,

1 America Electric Power, we're not directly  
2 interconnected with them, but they are interconnected  
3 with Duke. We would characterize that as an external  
4 transaction, but it's the same basis that we're  
5 willing to sell at a certain price, they're willing to  
6 buy at a certain price or vice versa. It's just that  
7 we're not directly interconnected and that's the  
8 difference.

9 Q Does Gulf apply the 20% shareholder  
10 incentive to both types of sales listed here?

11 A Yes, we do. Like I say, even though we do  
12 differentiate based on whether we're directly  
13 interconnected or not we still consider them as  
14 economy as you indicated, nonfirm hourly transactions.  
15 So we do apply the 80/20 split to the gain on both  
16 types of economy energy.

17 Q Under which FERC schedules does Gulf apply  
18 the 20% incentive?

19 A I'm sorry. Repeat that please.

20 Q Under which FERC schedules under sales,  
21 under which FERC schedules would Gulf apply that 20%  
22 incentive factor to?

23 A I don't know what the schedules are. I do  
24 know that we have two ways that we make economy  
25 transactions with directly interconnected utilities

1 and that's the split the savings concept that  
2 Mr. Wieland described. Those are, we have FERC  
3 schedules. I don't know what the names of them are.  
4 But the great bulk of our transactions now are under  
5 market based tariffs and I'm not sure what those  
6 tariffs are named. But both of those types of  
7 transactions we apply the 80/20 split to. It's any  
8 type of hourly, nonfirm transaction.

9 Q Whether it's split the savings pricing or  
10 market?

11 A Yes, sir. Whether it's split the savings or  
12 a market based type of transaction.

13 Q When Gulf participates in an economy energy  
14 transaction, is Gulf exceeding its obligation to  
15 provide cost-effective service to its retail  
16 ratepayers?

17 A I'm sorry. I don't understand the question.

18 Q Do you believe that when Gulf participates  
19 in an economy energy transaction that Gulf is  
20 exceeding its obligation to provide cost-effective  
21 electric service to its ratepayers?

22 A No, sir, I don't. As I said earlier, I  
23 think -- you know, before we have the incentive we  
24 engaged in this to try to benefit our customers where  
25 the stockholder got no benefit. But, I would hasten



1 to add that I certainly don't think that there is  
2 anything wrong with the incentive and we'll cover that  
3 I'm sure in great detail in my cross.

4 Q What incentives does Gulf have to purchase  
5 economy energy?

6 A The incentive we have to purchase economy  
7 energy is to offer our customers the greatest benefit  
8 because if we go ahead and generate with our resources  
9 then it would cost them more than if we purchased  
10 lower cost energy from somebody else during that hour  
11 so that's the incentive. 100% of the benefit, if you  
12 will, of that transaction goes to the customer.

13 Q So Gulf Power shareholders do not receive  
14 any direct financial incentive or benefit from these  
15 purchases?

16 A That's correct.

17 Q Okay. For your economy sales, what  
18 percentage are made in-state versus out-of-state?

19 A Well, let me answer it this way. Again,  
20 Gulf doesn't make any by itself. It makes them  
21 through the Southern Company and I really don't know  
22 what portion of our transactions are with the Florida  
23 companies as opposed to other companies. I just don't  
24 have that breakdown.

25 But I will say this, that we try to maintain

1 contact with all the Florida utilities, all the  
2 utilities adjacent to us and one system away to see  
3 what they might have for sale or what they might need  
4 to purchase. So it may vary hour by hour depending on  
5 what the needs of the parties are. But I don't have a  
6 feel for how that breaks down. To go further, we're  
7 not a member of the broker network, so none of ours  
8 are on the broker.

9 Q Just to clarify, is your projection filing  
10 based on Gulf applying the 20% incentive to more types  
11 of sales than you're currently applying it to?

12 A To more types of sales?

13 Q Right. To any other types of sales that  
14 you're not currently applying it to?

15 A No. No. Our projection is based on, you  
16 know, continuing the way we're doing it now. We don't  
17 anticipate applying an incentive to any other types of  
18 sales.

19 Q Okay. How does Gulf treat transmission  
20 revenues received from nonseparated, nonfirm wholesale  
21 sales not --

22 A We, of course, comply with the Commission  
23 order. This was an issue. We put forth our position  
24 to the Commission that because we had to return those  
25 two transmission customers as ordered by FERC in our

1 tariffs we propose that those should go into operating  
2 revenue. We were not successful in convincing the  
3 Commission that was the appropriate treatment and the  
4 Commission order specified that Gulf should put all of  
5 those into the fuel clause and that's what we  
6 currently do. Any transmission revenue we receive  
7 from nonfirm transmission transactions we do credit  
8 the customer 100% of those through the fuel clause.

9 Q Are transmission costs allocated to the  
10 various rate -- are transmission costs allocated to  
11 the various rate classes in a rate case on a demand  
12 basis?

13 A I don't have any idea.

14 Q If the Commission were to approve Staff's  
15 position on Issue 9, that is, if Gulf was required to  
16 flow transmission revenues from nonseparated wholesale  
17 energy sales through the capacity clause, would that  
18 decision impact your proposed factors?

19 A I'm sure it would because whatever those  
20 revenues are would flow as a credit through the  
21 capacity portion of the clause rather than the energy.  
22 It would certainly not impact the overall amount that  
23 the customer pays because we're providing 100% of  
24 those revenues to the customer. So it would impact --  
25 I do not know. I believe that information is

1 available here this morning if you need it rather than  
2 a late-filed, though.

3 COMMISSIONER CLARK: Mr. Howell, can I ask  
4 you a question?

5 WITNESS HOWELL: Yes, ma'am.

6 COMMISSIONER CLARK: You indicated most of  
7 your economy sales are at market prices?

8 WITNESS HOWELL: Yes, ma'am.

9 COMMISSIONER CLARK: But it's not Gulf  
10 that's making the sales? It's Southern Company?

11 WITNESS HOWELL: Yes, ma'am.

12 COMMISSIONER CLARK: How is it Southern  
13 Company is selling at market prices and not cost base  
14 prices?

15 WITNESS HOWELL: Let me give a simple  
16 example I think will explain that. Before the advent  
17 of market based pricing, which FERC did not allow  
18 under prior tariffs, you were required to transact  
19 with someone on a split the savings basis if that was  
20 what was in your tariff. And you had to quote your  
21 incremental price, they had to quote their decremental  
22 and you were required to transact at a split the  
23 savings price.

24 With the advent of the changes in the  
25 industry, FERC is allowing people to sell at whatever

1 the market will bear, if you will, a market price. So  
2 some utilities apparently don't have enough generation  
3 and they're willing to pay a pretty high premium for  
4 electricity rather than cut their customers off. So,  
5 utilities are assessing what the market is; what our  
6 customers -- what are utilities willing to pay for  
7 electricity and other utilities that have power for  
8 sale are charging that. So you've got basically two  
9 classes of utilities; those that have surplus power in  
10 a particular hour, those that don't have enough in a  
11 particular hour.

12 **COMMISSIONER CLARK:** Well, let me give you  
13 more information about the genesis of the question.  
14 If I understand, for instance, that Florida  
15 Power & Light and Florida Power Corporation cannot  
16 sell at market based rates within their region because  
17 they are a dominant transmission provider --

18 **WITNESS HOWELL:** Yes, ma'am.

19 **COMMISSIONER CLARK:** Now, I would assume  
20 Southern Company is a dominant transmission provider  
21 in their area.

22 **WITNESS HOWELL:** I'm not sure exactly what  
23 the -- what all of the requirements are at FERC. I do  
24 know this. That in the Southern System we did file  
25 our compliance tariffs. Initially each company had a

1 transmission rate. We then -- that was not accepted.  
2 We then tried a two zone rate within Southern and that  
3 was not accepted and basically what we were left with  
4 was we had a single transmission rate for the entire  
5 Southern Company; a postage stamp tariff, if you will.  
6 And in FERC's eyes that mitigated any market power we  
7 had because no longer was someone saying Mississippi  
8 had to pay three or four tariffs to get across  
9 Southern, they could just pay one.

10 So in FERC's eyes that mitigated that.  
11 That's not the situation in Florida. I'm saying that  
12 may be -- I don't know, but that may be why they can't  
13 do that. But we do not have that restriction because  
14 that's where I would guess over 95% of our  
15 transactions are market based transactions.

16 **COMMISSIONER CLARK:** Within your region?

17 **WITNESS HOWELL:** Well --

18 **COMMISSIONER CLARK:** It doesn't matter.

19 **WITNESS HOWELL:** It doesn't matter, yes. We  
20 can sell -- we comprise the entire subregion, the  
21 southern subregion of the SERC area and we're  
22 interconnected with just about all the parties in the  
23 SERC region. So we have market -- we have the ability  
24 to make those market based transactions.

25 **COMMISSIONER CLARK:** Thank you.

1           **Q**       **(By Mr. Keating)** Would Southern Company  
2 sell economy energy if at that time it was  
3 implementing load management or interrupting an  
4 interruptible customer?

5           **A**       Well, that's not a simple yes or no. Let me  
6 take them separately and address it that way. Okay?

7           **Q**       Okay.

8           **A**       If -- we have a lot of load management that  
9 is not active load management. Our position is right  
10 now that we would not implement the active load  
11 management at the same time we're selling off system.  
12 Our position at this point is that we have an  
13 obligation if we have enough electricity to not sell  
14 it off system and then cut customers who are on an  
15 interruptible rate. As far as if we would cut firm  
16 load, clearly we would never sell off system if we had  
17 to cut firm load.

18          **Q**       Do you believe it is more appropriate to  
19 credit transmission revenues to the fuel clause as  
20 opposed to the capacity clause? And I'm referring to  
21 the revenues, again, from nonseparated nonfirm  
22 wholesale sales.

23          **A**       I don't personally have a position on that.  
24 It's my understanding, subject to check, that Gulf  
25 Power doesn't have a strong position as to whether it



1 should be credited in the energy or the capacity  
2 clause. And, of course, this is all contingent. My  
3 feeling is, you know, we should credit those to  
4 operating revenues, but we lost that argument.

5 Q How does Gulf treat generation related gains  
6 on those types of sales?

7 A Which type of sales?

8 Q Nonseparated nonfirm wholesale energy sales?

9 A Okay. What we've been talking about is  
10 economy. The generation related gain is split 80/20.  
11 The stockholder keeps 80% of that gain. The customer  
12 keeps 80% of that gain.

13 MR. STONE: Mr. Howell.

14 WITNESS HOWELL: I'm sorry. Did I say it  
15 wrong?

16 MR. STONE: I think you may have.

17 WITNESS HOWELL: Let me start over. Right  
18 now the stockholder would like to keep 80% of the  
19 gain, but by Commission rule he's only allowed 20% of  
20 the gain and 80% is credited to the customer and,  
21 subject to check, it's my understanding that that goes  
22 through the energy component and not the capacity  
23 component, but I'm not the appropriate witness there.  
24 But that's my understanding.

25 Q (By Mr. Keating) Do you believe that the



1 fuel clause is the more appropriate place to record  
2 generation related gains than the capacity clause?

3       **A**     Like I said, I don't think -- I personally  
4 don't care and I don't think the company has a strong  
5 issue with that and that is subject to check. I don't  
6 see anybody raising steam over there.

7               **MR. KEATING:** Thank you, Mr. Howell. I have  
8 no further questions.

9               **COMMISSIONER DEASON:** Mr. Howell, I have a  
10 question or two.

11              **WITNESS HOWELL:** Yes, sir.

12              **COMMISSIONER DEASON:** Being that you're not  
13 part of Peninsular Florida, you do not participate in  
14 the Florida broker system; is that correct?

15              **WITNESS HOWELL:** Yes, sir. That's correct.

16              **COMMISSIONER DEASON:** Okay. And so the  
17 distinction between nonseparated wholesale sales being  
18 on the broker or not on the broker, that is a  
19 meaningless distinction for you?

20              **WITNESS HOWELL:** Yes, sir. That's correct.

21              **COMMISSIONER DEASON:** Okay. So, all of  
22 your -- what you refer to as economy sales, you apply  
23 the 80/20 split to those sales, correct?

24              **WITNESS HOWELL:** Yes, sir. The gain.

25              **COMMISSIONER DEASON:** The gain?

1                   **WITNESS HOWELL:** Yes, sir.

2                   **COMMISSIONER DEASON:** Okay. Now, I'm  
3 looking at the exhibit which Staff provided,  
4 Exhibit 26, and the last page of that. Even though  
5 you make a distinction between economy and external  
6 sales, in reality we can just consider both of those  
7 columns as what we refer to as economy?

8                   **WITNESS HOWELL:** Yes, sir. That's correct.

9                   **COMMISSIONER DEASON:** Okay.

10                  **WITNESS HOWELL:** It's just that they're  
11 characterized differently and we wouldn't want anybody  
12 auditing us to be confused by what we may say  
13 differently than what's on the books. But they are  
14 both economy transactions as I've described with the  
15 transmission distinction.

16                  **COMMISSIONER DEASON:** I'm trying to look at  
17 the trends in those numbers. It's kind of hard to  
18 ascertain if there's any trend one way or the other.  
19 Do you have an opinion on that?

20                  **WITNESS HOWELL:** Yes, sir. I think the  
21 trend is that we're certainly making more. We're  
22 certainly making more external sales which is two  
23 systems away than we used to because it started from  
24 zero. But then very quickly one would point out,  
25 well, in 1998 it turned around, so where is it headed.

1           And I think probably what we're going to see  
2   is the lack of a trend and these type of transactions  
3   really are driven by, does a utility have surplus  
4   capacity or is it temporarily short. And as systems  
5   around the southeast and the entire eastern seaboard  
6   add generation, they're going to be surplus. As they  
7   grow into that generation they're going to be short.  
8   And I think we're going to see it kind of go all over  
9   the place. I really don't think that there's a trend  
10  that's going to develop there.

11           **COMMISSIONER DEASON:** Okay. Thank you.

12           **WITNESS HOWELL:** Let me go ahead and add,  
13  Commissioner, that also if you look at the economy  
14  transactions you see that same thing; where we sold  
15  162 million in 1990 and 101 million in '94. It just  
16  goes up and down and that's simply because it's  
17  dependent upon other utility's need for electricity  
18  and our ability to have surplus in the hours that they  
19  might need it.

20           **COMMISSIONER DEASON:** Well, let me follow  
21  that up then. Well, then in your opinion, what impact  
22  does the 80/20 split have? If it's primarily driven  
23  by what surplus you have and perhaps what deficit your  
24  neighbors have, how does the 80/20 split work as an  
25  incentive to maximize these sales?

1                   **WITNESS HOWELL:** I think the way it works as  
2 an incentive is, clearly in today's market, as we see  
3 all utilities that I'm aware of moving away from split  
4 the savings they're going to marketing based  
5 transactions. The way you are successful in making  
6 transactions in a market based environment is you've  
7 got to know the market. If you don't have a Staff  
8 who's qualified, who's professional, who is able to  
9 track the market and know who needs power, who might  
10 have it for sale, then you're not going to be able to  
11 engage in that market.

12                   And if we make no profit off these sales --  
13 as I've said before, certainly any utility is going to  
14 try to maximize its ability to make economy  
15 transactions to the benefit of its customers. 100% of  
16 all the benefit of the purchases you make go to your  
17 customers anyway. But if we have the incentive of, we  
18 might be able to profit some for the stockholder then  
19 we can certainly justify a staff that tracks the  
20 market and is able to know what is out there. And  
21 that's why -- that's what our incentive then is and  
22 that's how that incentive works in the market based  
23 environment.

24                   And that's our concern about you all  
25 possibly adopting a position that you're going to

1 rescind the incentive. We believe the incentive  
2 works. I mean, it's an incentive. An incentive is  
3 something that modifies behavior to accomplish a goal.

4           The Commission that said we're going to  
5 establish this incentive believed in it and we want  
6 you to believe in it, too. If the incentive were  
7 removed and we no longer had a justification to track  
8 the market, to go after the market and know it, I'm  
9 firmly convinced that we would see our ability to make  
10 those transactions grow very much smaller, and you  
11 give our customers 80% -- I mean 100% of a real small  
12 pie, they're not going to benefit as much as if they  
13 get 80% of a big pie. And they are going to lose out  
14 entirely on all those transactions that in tracking  
15 the market we know of where we can go buy somewhere a  
16 little bit cheaper than what we can generate. If we  
17 lose the ability and the knowledge of that, they're  
18 going to lose all that benefit and they get 100% of  
19 that benefit.

20           That's why I guess the core of our  
21 disagreement with the other witnesses and the very  
22 concern we have is that our customers are going to  
23 suffer if the incentive is removed. I'm personally  
24 convinced of that. Our company is personally  
25 convinced of that. And certainly the stockholder is

1 going to see a small loss in profits, but, if you look  
2 at the amount of dollars involved here, it's not that  
3 big. But if we lose any incentive to fund this  
4 department and we have to keep funding the department  
5 out of operating profits right now, I think the  
6 customer is really going to lose and that's our big  
7 concern.

8 **COMMISSIONER DEASON:** Well, how is this  
9 department funded? Is it part of Southern Company  
10 Services which you receive an allocation and it's  
11 included in your base rates?

12 **WITNESS HOWELL:** Well, it's not really  
13 included in base rates, because right now our rates --  
14 eventually it might be, but right now until we go  
15 through a rate case or something it would not be in  
16 our base rates. We're just paying this. We've  
17 established the department in the last few years as a  
18 result of changes in the industry and are able to fund  
19 the department out of the 20% gain that we get. I  
20 don't think any of the companies have had a base rate  
21 increase where they've been able to incorporate those  
22 costs into it.

23 **COMMISSIONER DEASON:** Then are you saying  
24 that if there's an incentive that's adequate return  
25 and then you would not seek recovery of these type of

1 cost in base rates?

2           **WITNESS HOWELL:** I'm not a rate of return  
3 expert. I don't know.

4           **COMMISSIONER DEASON:** Okay. Have you given  
5 any thought to structuring an incentive which assumes  
6 there's going to be a certain base amount of  
7 transaction and the incentive would be applied to try  
8 to exceed that? Something similar to a GPIF?

9           **WITNESS HOWELL:** Yes, sir, I have. And if  
10 you go back to what the Staff passed out on Page 3,  
11 let me demonstrate that.

12           I've been around a long time and I maintain  
13 that it's very difficult to say what would have  
14 happened if. You ask yourself in a football game,  
15 what would have happened if.

16           **COMMISSIONER DEASON:** Commissioner Clark has  
17 been asking herself that question quite a bit.

18           **WITNESS HOWELL:** Well, over the years all of  
19 us, I'm sure, ask those questions. We don't know what  
20 would have happened if. Everybody has an opinion.  
21 But I don't think any of us really know what would  
22 happen if we remove the incentive as to what level we  
23 would have without the incentive.

24           Right now we see what we have and we see  
25 that is varies quite a bit, and we have the incentive



1 now. We've had it every year that the Staff has  
2 shown, 1990 through 1998.

3 What would it have been if we did not have  
4 the incentive. I don't think anybody really knows.  
5 And that, to me, is the difficulty in establishing  
6 some amount. How do you really know what the right  
7 amount is.

8 It would be unfair to the utility if you set  
9 the bar too high. It would be unfair to the customer  
10 if you set the bar too low. And that's why I'm firmly  
11 convinced that you just got to believe in what an  
12 incentive is. You just got to believe what human  
13 nature does and human nature responds to incentives.  
14 You try to get people to behave a certain way, you  
15 give them that incentive. And we don't know how, we  
16 don't know why, we just know they do it. We try to  
17 give incentives to our kids and we all know that have  
18 kids, some incentives work and some don't. But you  
19 find one that works, but the child does respond to the  
20 incentive, especially if it has to do with a car key.

21 So basic human behavior says, people do  
22 respond to incentives. Businesses respond to  
23 incentives. And that's why I'm firmly convinced that  
24 the incentive is the right thing. It's going to bring  
25 about the desired result. It's going to be a win-win



1 situation. And I'm afraid if we remove the incentive,  
2 we're going to have not a win-lose, win for the  
3 customer, lose for the utility; we are going to have  
4 lose-lose. If we can no longer justify tracking the  
5 market as closely as we do today, we don't have those  
6 opportunities to get the customer lower cost power  
7 that we might be aware of and we have to serve it of  
8 our own generation, which we have to acknowledge, no  
9 utility can always serve its load every hour at the  
10 lowest cost out of its own generation. Somebody is  
11 going to have some cheaper in some hours. So that  
12 would be my answer to that.

13 **COMMISSIONER JACOBS:** You indicated earlier  
14 that there is some apparent willingness on the part of  
15 customers to pay a premium.

16 **WITNESS HOWELL:** Utilities -- yes, sir, that  
17 are apparently willing to pay whatever the market will  
18 bear and, Commissioner, is that what you're referring  
19 to when we were talking about paying the market  
20 premium?

21 **COMMISSIONER JACOBS:** Right.

22 **WITNESS HOWELL:** Clearly I think we see a  
23 lot of utilities and a lot of hours don't have enough  
24 generation to really serve their load.

25 **COMMISSIONER JACOBS:** Isn't that going to be

1 the driving force? I mean, at some point there's  
2 going to be a margin out there that people are going  
3 to pursue and -- well, let me ask you this. How would  
4 you characterize the movement of the other companies  
5 off broker? Isn't that reflective of that idea?

6 **WITNESS HOWELL:** I think so. And I will  
7 acknowledge that I'm not that familiar. I was very  
8 familiar with the broker when it was -- first came  
9 into being, but I'm not that familiar with utilities'  
10 actions since then. But the broker, at the time I was  
11 very familiar with it, was voluntary. A utility could  
12 voluntarily put in a decremental price at an  
13 incremental price, but they were not required to.

14 I think if I were a utility in Florida, and  
15 I were -- and I had some capacity available and I kind  
16 of knew what I could get because they could track this  
17 over time and I knew how much profit I could make off  
18 the broker, and if perhaps the market out there  
19 offered me greater profits, we all know that's an  
20 incentive. That's what I'm talking about. The  
21 incentive is to not to sell on the broker. You're not  
22 required to. You go out and sell on the market where  
23 the gains are higher and I think that may be what has  
24 happened in Florida.

25 **COMMISSIONER JACOBS:** So then sounds like

1 what we might want to do is look at an incentive which  
2 tracks what margin is available as opposed to an  
3 automatic situation or incentive.

4 In other words, if we can look at the market  
5 price, prevailing market price and make some  
6 determination whether or not companies are going to go  
7 to market based pricing, sounds to me then that an  
8 alternative incentive such as a hard, fast incentive  
9 could be sacrificed.

10 **WITNESS HOWELL:** I really think,  
11 Commissioner, we have that now because the thing about  
12 a market is it varies, the electricity market  
13 particularly. It just varies all over the place.  
14 It's very high in some hours in the summer and, of  
15 course, there really is no market like in the wee  
16 hours of the morning on April 1st, when nobody wants  
17 to buy any.

18 But whatever the market price is, it varies  
19 each hour and nothing that Gulf or Southern or any  
20 Commission or any utility can do can change that. It  
21 has to do with the relationship of whatever the loads  
22 and demands on the system are, which are mostly  
23 weather related, and how much generation the company  
24 may have, and what's happened with this forced  
25 outages, that type of thing. So nobody can control

1 the market. It is what it is.

2 And what we do is, whatever that market  
3 price is, if we're a seller, we take that gain which  
4 is whatever we're able to sell it at above our cost,  
5 that's the gain, and we split that right now among --  
6 between the stockholders and the customers. So I  
7 think we have the -- I think we have that in place at  
8 this time.

9 COMMISSIONER JACOBS: Okay. Thank you.

10 COMMISSIONER CLARK: Mr. Howell, do you have  
11 an overall sort of view of the prices for these sales  
12 since you opened up -- Southern Company opened up  
13 their transmission system? Are you able to buy power  
14 when you need it?

15 WITNESS HOWELL: Yes, ma'am. So far we have  
16 been able to buy --

17 COMMISSIONER CLARK: But it is cheaper for  
18 you or --

19 WITNESS HOWELL: Well, we would always  
20 generate it with our own resources if we could unless  
21 somebody has some cheaper and, yes, ma'am, there are  
22 situations where they have it cheaper than we do and  
23 that's when we like to buy. On the converse, when we  
24 have it cheaper than they do, that's when we like to  
25 sell.

1           **COMMISSIONER CLARK:** Let me ask the question  
2 again maybe more precisely. Since you have gone to  
3 the postage stamp rate for your transmission system  
4 and you have been allowed to charge --

5           **WITNESS HOWELL:** Market rates.

6           **COMMISSIONER CLARK:** -- market rates --

7           **WITNESS HOWELL:** Yes, ma'am.

8           **COMMISSIONER CLARK:** -- is it your  
9 experience that the prices when you want to purchase  
10 have been lower than they otherwise were before that  
11 change?

12           **WITNESS HOWELL:** Well, let me answer it this  
13 way. I think because we have the transmission system  
14 opened up as you characterize it there, yes, ma'am, we  
15 are able then to buy power from anybody. But the  
16 problem is, before we had -- before we opened up the  
17 transmission system capacity was not as short as it is  
18 now and it's difficult to go back and compare what  
19 happened in the past to what happened now.

20           But, certainly because we can buy this stuff  
21 cheaper, I think -- I don't think that's as big a  
22 factor as FERC says, you can't sell it at market  
23 prices unless you open up your transmission system.  
24 FERC's idea is to improve national efficiency and they  
25 don't care if your system is opened up or not if

1 you're a buyer. They do care if you sell. They don't  
2 want you to have market power to sell without opening  
3 up your system. And I hope that was responsive to the  
4 question.

5 **COMMISSIONER CLARK:** But having the post --  
6 maybe just having the postage stamp has increased the  
7 number of people willing to sell into your market.

8 **WITNESS HOWELL:** Probably has, simply  
9 because there's just more transactions going on.

10 **COMMISSIONER CLARK:** Okay.

11 **WITNESS HOWELL:** But if we look at Staff's  
12 exhibit they passed out, we've had that open access, I  
13 guess, since '96 or so. And you look at those years  
14 where the economy transactions were 32, 76 and  
15 52 million, those are really small compared to, say,  
16 the three prior years.

17 So, I find it difficult to track it because  
18 the real thing driving that is how much generation do  
19 you have and how much generation do they have. And  
20 Southern has been in more of a short position compared  
21 to prior years. And that's why, even with the market  
22 rates that we can charge, we haven't sold as many  
23 kilowatt hours, say, in the last three years as we did  
24 the prior three.

25 **COMMISSIONER CLARK:** Well, let me ask this



1 question. Has Southern seen it to their benefit to  
2 buy rather than build?

3 **WITNESS HOWELL:** Yes, ma'am. And that  
4 varies through time. One of the things that we found,  
5 let's say two or three years ago, is that there  
6 appeared to be a surplus of power in the southeast.  
7 So Southern, and Gulf, of course, gets its share of  
8 that, has bought some extremely inexpensive power that  
9 would be much cheaper to buy than it would be to  
10 build.

11 Now, what we've seen in the last year or so  
12 is that excess or surplus in the southeast is dried up  
13 and at this time point in time, it is more expensive  
14 to buy than it is to build. Our forecast says that at  
15 some point you're going to reach equilibrium and it  
16 should be about the same. In fact, I think we'll find  
17 in a competitive market that you're always maybe just  
18 a little above or a little below capacity compared to  
19 the market. But at this point in time today, if you  
20 go try to buy power right now for year 2000, it will  
21 cost you more than if you had built capacity for the  
22 2000. That not the case two years ago.

23 **COMMISSIONER CLARK:** Okay.

24 **COMMISSIONER DEASON:** Redirect?

25 **MR. STONE:** No redirect.

1 COMMISSIONER DEASON: Exhibits?

2 MR. STONE: We move Exhibits 25 and 26 into  
3 the record.

4 COMMISSIONER DEASON: Without objection.  
5 Hearing none, Exhibits 25 and 26 are admitted.

6 MR. KEATING: Staff would move its exhibit.  
7 I believe ours was Exhibit 26.

8 MR. STONE: We adopted it.

9 MR. KEATING: Thank you.

10 (Exhibits 25 and 26 received in evidence.)

11 MR. WILLIS: Call Karen Zwolak.

12 COMMISSIONER DEASON: Very well.

13 MR. KEATING: Commissioners, before we bring  
14 Ms. Zwolak to the stand, this is a witness that Staff  
15 until this morning had intended to ask some questions  
16 from and unless the other parties have questions for  
17 this witness, we think we can stipulate her testimony  
18 into the record.

19 COMMISSIONER DEASON: Very well.

20 MR. MCWHIRTER: I got a couple of questions  
21 for her.

22 COMMISSIONER DEASON: Okay. Mr. McWhirter  
23 has questions.

24 MR. KEATING: Okay.

25 MR. MCWHIRTER: You don't get to talk to a



1 microbiologist every day.

2 - - - - -

3 KAREN O. ZWOLAK

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

7 DIRECT EXAMINATION

8 BY MR. WILLIS:

9 Q Please state your name and address?

10 A Karen Zwolak. 702 North Franklin Street,  
11 Tampa, Florida 33602.

12 Q Did you prepare and cause to be prefiled on  
13 April 1st prepared testimony in this docket?

14 A Yes, I did.

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

17 A There are two revisions due to the  
18 stipulated issue on the refund that was removed from  
19 my exhibits and stricken from my testimony.

20 Q Well, let's start with the April 1st  
21 testimony.

22 A Uh-huh.

23 Q Are there any additions and corrections to  
24 your April 1st testimony?

25 A My April 1st testimony there was a revision

1 filed on October 1st correcting the first page of that  
2 exhibit.

3 Q All right. To the exhibit, but no changes  
4 to your testimony?

5 A There was a change to the testimony as well.  
6 On Page 4, Line 17, the \$11,830,891 should be replaced  
7 with the number I have on the revision of \$7 million.  
8 That number should be \$7,700 -- \$7,879,936.

9 Q With that correction, would your answers be  
10 the same today?

11 A Yes, they would.

12 MR. WILLIS: I ask that Ms. Zwolak's April  
13 1st testimony be inserted into the record as though  
14 read.

15 COMMISSIONER DEASON: Without objection it  
16 should be so inserted.

17

18

19

20

21

22

23

24

25

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

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

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

A. I received a Bachelor of Arts Degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I transferred to Tampa

1 Electric's Energy Supply Department and assumed the duties  
2 of the plant chemical engineer at the F. J. Gannon Station.  
3 In this position, I was responsible for boiler chemistry,  
4 water management, and maintenance of environmental  
5 equipment and general engineering support. In 1997, I was  
6 promoted to Manager, Energy Issues in the Electric  
7 Regulatory Affairs Department. My present responsibilities  
8 include the areas of fuel adjustment, capacity cost  
9 recovery, environmental filings and rate design.

10  
11 Q. What is the purpose of your testimony in this proceeding?

12  
13 A. The purpose of my testimony is to present the net true-up  
14 amounts for April 1998 through December 1998 period for  
15 both the Fuel and Purchased Power Cost Recovery and the  
16 Capacity Cost Recovery Clauses.

17  
18 **FUEL AND PURCHASED POWER COST RECOVERY CLAUSE**

19  
20 Q. What is the net true-up amount for the fuel and purchased  
21 power cost recovery clause for the period April 1998  
22 through December 1998?

23  
24 A. The net true-up is an over-recovery of \$11,830,891.. The  
25 actual fuel cost over-recovery, including interest, is

1 \$17,092,004 for the period April 1998 through December  
2 1998. This \$17,092,004 amount, less the actual/estimated  
3 over-recovery approved in the November 1998 fuel hearings  
4 of \$5,261,113 results in a final over-recovery for the  
5 period of \$11,830,891. This over-recovery amount of  
6 \$11,830,891 will be carried over and applied in the  
7 calculation of the fuel recovery factor for the period  
8 January 2000 through December 2000.

9  
10 Q. How much effect will this \$11,830,891 over-recovery, in the  
11 April 1998 through December 1998 period, have on the  
12 January 2000 through December 2000 period?

13  
14 A. The \$11,830,891 over-recovery will cause a 1,000 KWH  
15 residential bill to be approximately \$0.74 lower.

16  
17 Q. Have you prepared an Exhibit in this proceeding?

18  
19 A. Yes. I have prepared exhibit No. (KOZ-1, Fuel and  
20 Purchased Power Cost Recovery and Capacity Cost Recovery)  
21 which contains four documents. Document No. 1 is entitled  
22 ❖Tampa Electric Company Final Fuel Over-Recovery for the  
23 period April 1998 through December 1998" and Document No.  
24 2 is entitled ❖Tampa Electric Company Calculation of True-Up  
25 Amount Actual vs. Original Estimates for the period April

1 1998 through December 1998. Document No. 3 is used to  
2 explain the capacity cost recovery clause which is  
3 discussed later in my testimony. Document No. 4 contains  
4 Commission Schedules A-1 through A-9 for the months of  
5 April 1998 through December 1998. Included with the  
6 December 1998 monthly filing is a nine-month summary for  
7 each of Commission Schedules A6, A7, A8, and A9 for the  
8 period April 1998 through December 1998. Document No. 5  
9 provides the true-up amount calculated for the Temporary  
10 Base Rate Reduction.

11  
12 Q. Please explain Document No. 1.

13  
14 A. Document No. 1, entitled "Tampa Electric Company Final Fuel  
15 Over - Recovery for the period April 1998 through December  
16 1998" shows the calculation of the final fuel over-recovery  
17 for the period of \$11,830,891 which will be applied to  
18 jurisdictional sales during the period January 2000 through  
19 December 2000.

20  
21 Line 1 shows the total company fuel costs of \$281,149,525  
22 for the period April 1998 through December 1998. The  
23 jurisdictional amount of total fuel costs is \$281,501,223  
24 as shown on line 2. This amount is compared to the  
25 jurisdictional fuel revenues applicable to the period on

1 line 3 to obtain the actual over-recovered fuel costs for  
2 the period, shown on line 4. The resulting \$16,834,096  
3 over-recovered fuel costs for the period, combined with  
4 \$257,908 of interest shown on line 5, constitute the actual  
5 over-recovery of \$17,092,004 shown on line 6. The  
6 \$17,092,004 less the actual/estimated over-recovery of  
7 \$5,261,113 shown on line 7, which was approved in the  
8 November 1998 fuel hearings, results in the final over-  
9 recovery of \$11,830,891 shown on line 8.

10

11 Q. Please explain Document No. 2.

12

13 A. Document No. 2, entitled "Tampa Electric Company  
14 Calculation of True-Up Amount Actual vs. Original Estimates  
15 for the period April 1998 through December 1998," shows the  
16 calculation of the actual over-recovery as compared to the  
17 original estimate for the same period.

18

19 Q. What was the variance in jurisdictional fuel revenues for  
20 the period April 1998 through December 1998?

21

22 A. As shown on line C1 of my Document No. 2, the company  
23 collected \$8,724,480 more jurisdictional fuel revenues than  
24 originally estimated.

25



1 Q. What was the total fuel and net power transaction cost  
2 variance for the period April 1998 through December 1998?

3  
4 A. As shown on line A7 of Document No. 2, the fuel and net  
5 power transactions cost variance is \$10,001,582 or 3.4%  
6 less than originally projected.

7  
8 Q. What are the reasons for the total fuel and net power  
9 transactions cost being lower by \$10,001,582 or 3.4%?

10  
11 A. The primary reason for the 3.4% decrease is due to an  
12 increase in the Net Energy for Load of 283,499 MWH or 2.2%.  
13 This 2.2% combined with the decrease in fuel cost (¢/KWH)  
14 for Total Fuel and Net Power Transaction of 5.5% from the  
15 estimate, accounts for the 3.4% decrease.

16

17 **CAPACITY COST RECOVERY CLAUSE**

18

19 Q. What is the net true-up amount for the capacity cost  
20 recovery clause for the period April 1998 through December  
21 1998?

22

23 A. The net true-up amount is an over-recovery of \$442,999.  
24 The actual capacity cost under-recovery, including  
25 interest, is \$732,421 for the period April 1998 through



1 December 1998 as identified in Document No. 3, pages 2 and  
2 3 of 6. This amount, less the actual/estimated under-  
3 recovery approved in the November 1998 fuel hearings of  
4 \$1,175,420 results in a final over-recovery for the period  
5 of \$442,999 as identified in Document No. 3, page 6 of 6.  
6 This over-recovery amount of \$442,999 will be carried over  
7 and applied in the calculation of the capacity cost  
8 recovery factor for the period January 2000 through  
9 December 2000.

10  
11 **Q.** How much effect will this \$442,999 over-recovery in the  
12 April 1998 through December 1998 period, have on the  
13 January 2000 through December 2000 period?

14  
15 **A.** The \$442,999 over-recovery will cause a 1,000 KWH  
16 residential bill to be approximately \$0.03 lower.

17  
18 **TEMPORARY BASE RATE REDUCTION**

19  
20 **Q.** What is the actual amount credited to customers through the  
21 Temporary Base Rate Reduction?

22  
23 **A.** As specified in the stipulation reached in Docket No.  
24 960409-EI approved in Order No. PSC-96-1300-S-EI, issued  
25 October 24, 1996, Tampa Electric agreed to provide a

1 temporary base rate reduction to customers in the total  
2 amount of \$25 million over 15 months starting with the  
3 effective date of the first billing cycle from October 1,  
4 1997 through December 31, 1998. The amount actually  
5 credited to customers through the Temporary Base Rate  
6 Reduction was \$25,435,939. This resulted in \$435,939 more  
7 than the \$25 million amount agreed upon in the stipulation.  
8

9 **Q.** How will this excess credit to customers be collected?  
10

11 **A.** Order No. PSC-96-0670-S-EI states that any over- or under-  
12 collection associated with the credit will be handled as a  
13 true-up component in the normal course of Tampa Electric's  
14 fuel cost recovery proceedings. However, due to the  
15 sharing plan approved in this order, Tampa Electric has  
16 agreed to refund any revenues contributing to a net ROE in  
17 excess of 12.75% for 1998. Because Tampa Electric is  
18 within the 100% sharing range for 1998, any additional  
19 revenues such as this excess credit to customers of the  
20 Temporary Base Rate Reduction would ultimately be refunded  
21 to customers. Therefore, Tampa Electric proposes not to  
22 recover this excess credit in the true-up. This avoids  
23 collecting the excess credit from customers only to turn  
24 around and refund it under the deferred revenue calculation  
25 formula. In other words, this appears to be the simplest

1 method for handling the excess credit.

2

3 Q. Does this conclude your testimony?

4

5 A. Yes.

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1           **MR. WILLIS:** We also requested her 160 page  
2 exhibit as the first page of that exhibit was  
3 corrected by filing on October 1st be identified.

4           **COMMISSIONER DEASON:** It will be identified  
5 as Exhibit 27.

6           (Exhibit 27 marked for identification.)

7           **Q**       **(By Mr. Willis)** All right. Ms. Zwolak,  
8 did you prepare and cause to be prefiled testimony on  
9 October 1st in this docket?

10          **A**       Yes, I did.

11          **Q**       Do you have any additions or corrections to  
12 that testimony?

13          **A**       The corrections I just mentioned, we have  
14 removed the testimony and documents that refer to the  
15 refund from the earnings docket.

16          **MR. WILLIS:** Commissioner, I request that a  
17 correction sheet of Ms. Zwolak's testimony be marked  
18 as an exhibit and entered into the record.

19          **COMMISSIONER DEASON:** It shall be identified  
20 as Exhibit 28.

21          (Exhibit 28 marked for identification.)

22          **Q**       **(By Mr. Willis)** With the corrections on  
23 Exhibit 28 added to your testimony, would your answers  
24 be the same today?

25          **A**       Yes, they would.

1           **MR. WILLIS:** We would request that  
2       Ms. Zwolak's October 1st testimony be inserted in the  
3       record as though read.

4           **COMMISSIONER DEASON:** Without objection it  
5       shall be so inserted.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

A. My name is Karen O. Zwolak. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues in the Regulatory Affairs Department of Tampa Electric

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

A. I received a Bachelor of Arts Degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I

1 transferred to Tampa Electric's Energy Supply Department  
2 and assumed the duties of the plant chemical engineer at  
3 the F. J. Gannon Station. In 1997 I was promoted to  
4 Manager, Energy Issues in the Electric Regulatory Affairs  
5 Department. My present responsibilities include the  
6 areas of fuel, capacity, and environmental cost recovery  
7 filings and energy issues and rate design.

8  
9 Q. What is the purpose of your testimony?

10  
11 A. The purpose of my testimony is to present to the  
12 Commission the proposed total fuel and purchased power  
13 cost recovery factors and the proposed capacity cost  
14 recovery factors for January 2000 through December 2000.  
15 I will also describe significant events that affect the  
16 factors. Finally, I will provide an overview of the  
17 composite effect from the various cost recovery factors  
18 for 2000.

19  
20 Q. Have you prepared an exhibit to support your testimony?

21  
22 A. Yes. Exhibit No. 29 (KOZ-2), Document No. 1 is  
23 comprised of Schedules H-1 for January - December 1997  
24 through 2000 and Schedules E-1 through E-10 for January  
25 2000 - December 2000. Also contained in this exhibit are

1 Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the  
2 current cost recovery period of January through December  
3 1999. These schedules are furnished as support for the  
4 projected true-up for this period and consist of eight  
5 actual months and four projected months. These schedules  
6 are included in Exhibit No. 29 (KOZ-2), Document No. 1  
7 Fuel Projection.

8  
9 Fuel and Purchased Power Cost Recovery Factors

10  
11 Q. What is the appropriate value of the fuel adjustment for  
12 the year 2000?

13  
14 A. The appropriate value for the new period is 2.243 cents  
15 per kilowatt hour ("kwh") before the normal application  
16 of factors that adjust for variations in line losses.  
17 Schedule E-1 of Exhibit No. 29 (KOZ-2), Fuel Projection,  
18 shows the appropriate values for the total fuel and  
19 purchased power cost recovery clause as projected for the  
20 period January 2000 through December 2000.

21  
22 Q. Please describe the information provided on Schedule E-  
23 1C.

24  
25 A. The GPIF and true-up factors are provided on Schedule E-



1C. Tampa Electric has calculated a GPIF penalty of \$276,901 which is to be included in the calculation of the total fuel and purchased power cost recovery fuel factors.

Additionally E-1C indicates the net true-up amount for the January through December 1999 period. The net true-up amount for this period is an under-recovery of \$3,666,883. This under-recovery is comprised of a final true-up over-recovery amount of \$7,879,936 for the April 1998 through December 1998 period and an estimated under-recovery in the amount of \$11,546,819 for the January 1999 through December 1999.

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

A. Schedule E-1D presents Tampa Electric's on-peak and off-peak fuel charge factors for January 2000 through December 2000.

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. Please summarize the proposed Fuel and Purchased Power Cost Recovery factors by rate schedule for January 2000 through December 2000.

A.	Fuel Charge
<u>Rate Schedule</u>	<u>Factor (cents per kwh)</u>
Average Factor	2.243
RS, GS and TS	2.259
RST and GST	3.074 (on-peak)
	1.905 (off-peak)
SL-2, OL-1 and OL-3	2.080
GSD, GS LD, and SBF	2.247
GSDT, GS LDT, EV-X and SBFT	3.057 (on-peak)
	1.895 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.171
IST-1, IST-3, SBIT-1, SBIT-3	2.955 (on-peak)
	1.832 (off-peak)

Q. How does Tampa Electric's proposed average fuel charge factor of 2.243 cents per kwh compare to the average fuel charge factor for the January 1999 through December 1999 period?

1 A. The proposed fuel charge factor is 0.029 cents per kwh  
2 (or \$0.29 per 1000 kwh) higher than the average fuel  
3 charge factor of 2.214 cents per kwh for the January  
4 through December 1999 period.

5  
6 Capacity Cost Recovery Clause

7  
8 Q. Are you also requesting Commission approval of the  
9 projected capacity cost recovery factors for the  
10 company's various rate schedules?

11  
12 A. Yes. The capacity cost recovery factors, prepared under  
13 my direction or supervision, are provided in Exhibit No.  
14 29 (KOZ-3), Capacity Cost Recovery.

15  
16 Q. What payments are included in Tampa Electric's capacity  
17 cost recovery factor?

18  
19 A. Tampa Electric is requesting recovery through the  
20 capacity cost recovery factor of capacity payments for  
21 purchases of power made for retail and all-requirements  
22 customers excluding optional provision purchases for  
23 interruptible customers.

Q. Please summarize the proposed capacity cost recovery clause factors by rate schedule for January 2000 through December 2000.

A.	Capacity Cost Recovery
<u>Rate Schedule</u>	<u>Factor (cents per kwh)</u>
RS	0.271
GS and TS	0.230
GSD, EV-X	0.187
GSLD and SBF	0.169
IS-1, IS-3, SBI-1, SBI-3	0.015
SL-2, OL-1 and OL-3	0.054

These factors are shown in Exhibit No. 29 (KOZ-3), page 3 of 5.

Q. How does Tampa Electric Company's proposed average capacity cost recovery factor of 0.204 cents per kwh compare to the factor for 1999?

A. The proposed capacity cost recovery factor is .048 cents per kwh (or \$0.48 per 1000 kwh) higher than the average capacity cost recovery factor of 0.156 cents per kwh for the January through December 1999 period.

Events Affecting the Projection Filing

Q. Are there any events reflected in the calculation of the 2000 Fuel and Purchased Power and Capacity Cost Recovery projections that are not reflected in last year's projections?

A. Yes. There are six events. These are: 1) the stipulation entered into in Docket No. 980001-EI relating to heat content adjustments in the Gatliff Coal contract, 2) the Gannon Unit 6 accident, 3) new purchased power agreements, 4) the advanced in-service date of a 180-megawatt combustion turbine ("CT"), 5) the requested treatment for the FMPA wholesale power supply agreement, and 6) the refund associated with Docket No. 960409-EI.

Q. Please describe the first event, a reduction in the 1999 projections as the result of the stipulation entered into in Docket No. 980001-EI, Order No. PSC-98-1715-FOF-EI issued on December 18, 1998).

A. As the order reflects, Tampa Electric stipulated to reduce its projected fuel and purchased power costs by \$6,639,522. This was done to settle an issue raised by Commission Staff regarding Tampa Electric's inclusion of

1 heat content adjustments in comparing Gatliff prices to  
2 the benchmark price.

3  
4 Q. Has the refund been completed?

5  
6 A. Yes. Tampa Electric adjusted the fuel and purchased  
7 power costs by \$6,639,522 to reflect purchases from 1993  
8 through 1997 and to also adjust costs to reflect the  
9 amount expected to be incurred in 1998. In total, Tampa  
10 Electric actually reduced the Fuel and Purchased Power  
11 Cost Recovery Clause in 1999 by \$7,280,088. The total  
12 cost of Gatliff Coal purchased in excess of the benchmark  
13 for 1998 was \$629,267 as identified in Tampa Electric  
14 witness Mark J. Hornick's testimony. The company had  
15 estimated the 1998 over-benchmark component to be  
16 \$610,593 which was included in the adjustment. The  
17 difference associated with the true up for 1999 is  
18 \$18,674 (\$629,267 less \$610,593) and the adjustment  
19 associated with interest for the true up is \$9,540  
20 totaling a net adjustment of \$9,134. This is included in  
21 the calculation for the proposed fuel adjustment factor  
22 for the year 2000 and is reflected in Schedule E-1.

23  
24 Q. Please describe the second event that impacts the  
25 company's projection filing.

1     **A.**    The second event that affects the filing is the April 8,  
2            1999 Gannon Unit 6 accident. Details regarding the  
3            accident are discussed in the testimonies of Tampa  
4            Electric witnesses Charles R. Black and Mark D. Ward.  
5            The company incurred \$5,073,526 for replacement fuel and  
6            purchased power as a result of the accident. These costs  
7            are included in Schedules E-2 and E-8, which reflect  
8            actual/estimated costs for the current period January  
9            1999 through December 1999.

10

11    **Q.**    Please describe the third event.

12

13    **A.**    In an effort to improve system reliability for retail  
14            ratepayers in 1999, 2000 and beyond at reasonable and  
15            prudent costs, Tampa Electric explored many options.  
16            After a review process, the company negotiated five  
17            purchased power agreements. The testimony of Tampa  
18            Electric Company witness W. L. Brown describes these  
19            purchases and demonstrates that the costs associated with  
20            these purchased power agreements are prudent and  
21            appropriate for recovery through the Fuel and Purchased  
22            Power Cost Recovery clause.

23

24    **Q.**    Please describe the fourth event that impacts the  
25            company's projection filing.

1    **A.**   The fourth event is the advancement of the in-service  
2           date for Tampa Electric's next generation unit, a 180 MW  
3           CT. According to the company's Ten-Year Site Plan filed  
4           with this Commission in April 1999, this unit was shown  
5           to have a commercial in-service date of January 2001. In  
6           order to maintain reliability for its native load, the  
7           company has decided to accelerate the in-service date to  
8           October 2000. The associated natural gas and distillate  
9           oil costs are included in generation costs for the year  
10          2000.

11  
12   **Q.**   Please describe the fifth event that impacts the  
13          company's projection filing.

14  
15   **A.**   The fifth event relates to the company's proposed  
16          treatment of its wholesale power supply agreement with  
17          FMPPA for January 1, 2000 through March 15, 2001. This  
18          proposed treatment is described in the testimony of Tampa  
19          Electric witness Thomas L. Hernandez. Tampa Electric's  
20          Fuel and Purchased Power Cost Recovery Clause factors  
21          reflect this proposed treatment for the period January 1,  
22          2000 through December 31, 2000.

23  
24   **Q.**   Please describe the sixth event that impacts the  
25          company's projection filing.



1    **A.**    The sixth event relates to the refund contemplated in  
2           Order No. PSC-96-1300-S-EI from Docket No. 960409-EI.  
3           The order specifies that the total refund paid out in  
4           1999 is to be provided to customers at a rate of \$2  
5           million per month until the entire refund is exhausted.  
6           The refund is to be reflected as a credit on customer's  
7           bills calculated by multiplying a levelized factor  
8           adjusted for line losses times the actual kwh usage for  
9           the period of the refund, as shown in Exhibit 29 (KOZ-4).  
10          The refund is to include interest on the unamortized  
11          amount of the refund.

12  
13          Based upon the refunds determined by the Commission in  
14          its proposed agency actions ("PAA") from the agenda  
15          conferences held on August 31, 1999 and September 7, 1999  
16          for the review of 1997 and 1998 earnings, respectively,  
17          the total amount to be refunded is \$11,226,598. This  
18          amount plus interest will be refunded to customers  
19          beginning in January 2000 at a rate of approximately \$2  
20          million over a six-month period, assuming there are no  
21          protests of the Commission's PAA orders affecting the  
22          amount to be refunded.

23  
24          Cost Recovery Factors  
25

1 Q. What is the composite effect of Tampa Electric's proposed  
2 changes in its various cost recovery factors on a 1000  
3 kwh residential customer?  
4

5 A. A residential bill for 1000 kwh will increase \$0.43  
6 beginning January 2000. These factors are shown in  
7 Exhibit 29 (KOZ-2), Document No. 2.  
8

9 Q. When should the new rates go into effect?  
10

11 A. The new rates should go into effect concurrent with the  
12 first billing cycle in January 2000.  
13

14 Q. Does this conclude your testimony?  
15

16 A. Yes it does.  
17  
18  
19  
20  
21  
22  
23  
24  
25

1           **MR. WILLIS:** We request that a 48 page  
2 Composite Exhibit which is attached to her testimony  
3 by identified please.

4           **COMMISSIONER DEASON:** Exhibit 29.

5           (Exhibit 29 marked for identification.)

6           **MR. WILLIS:** We would note that the last  
7 page of that exhibit has been withdrawn which is --  
8 would be Page 49, as noted in her correction.

9   **BY MR. WILLIS:**

10           **Q**     Could you please summarize your testimony?

11           **A**     Yes, I could. Good morning, Commissioners.  
12 My testimony and exhibits show the calculation of the  
13 fuel and purchased power cost recovery clause as well  
14 as the capacity cost recovery clause factors to be  
15 applied by Tampa Electric in the year 2000. That  
16 summarized my testimony. Thank you.

17           **MR. WILLIS:** I tender the witness.

18           **COMMISSIONER DEASON:** Mr. McWhirter.

19                   **CROSS EXAMINATION**

20   **BY MR. MCWHIRTER:**

21           **Q**     Ms. Zwolak, would you go to Page 11 of  
22 Exhibit 29?

23           **A**     Exhibit 29? I'm sorry. In my excitement of  
24 being excused I left my back-up book behind. Could  
25 you tell me again?

1 Q Yes. Page 11.

2 A Of the exhibit or the testimony?

3 Q Of the exhibit.

4 A Yes.

5 Q Columns D, E and F of that exhibit provide  
6 the net capacity factor, the equivalent availability  
7 factor and the net output factor of each of the  
8 utility's installed generating stations. Are you  
9 familiar with the methodology used to develop those  
10 factors?

11 A No, I'm not. That data is developed from  
12 our production department in conjunction with our  
13 resource planning department.

14 Q All right. I will ask no further questions  
15 about that. Will you go to Page 8. And this page  
16 represents your actual fuel cost on a month by month  
17 basis that you use to develop the average fuel cost.  
18 Prior to this year we set the fuel factor twice a  
19 year. Once for the period of October through March  
20 and the second time April through September; is that  
21 correct?

22 A That is correct. Although the page you're  
23 referring to, 8, is not actuals.

24 Q Can you talk into the microphone. I can't  
25 hear you.

1           A     I'm sorry. The page you're referring to are  
2 not actuals. Those are projections for 2000.

3           Q     I'm not going to ask you to do this  
4 calculation, but I have done it and if you think that  
5 it's -- I'm misstating the facts then please quickly  
6 clarify. But it appears to me if you look at Line 8  
7 it gives your monthly fuel cost for each of the 12  
8 months of the year; is that correct?

9           A     Yes, it does.

10          Q     And if you looked at the former period used  
11 for establishing the factor, which would be April  
12 through September, is it not fair to say that 65% of  
13 your total annual cost is incurred in that period of  
14 time?

15          A     I could not tell you the percentages, but  
16 the summer months appear to be higher.

17          Q     And then for the other six month period,  
18 would take about 35% of your fuel cost; is that right?

19          A     Again, I could not verify your percentages.

20          Q     Would it be fair to say from your basic  
21 understanding of the information you put together that  
22 when you set the fuel factor twice a year, once for  
23 the time when you consumed -- when you have the  
24 greatest cost and once for the time when you have less  
25 cost, those factors would more closely track cost than

1 if you do it one time a year?

2 A I really hadn't looked into it in detail,  
3 but you may be right.

4 Q All right. Would you go to Page 36 of your  
5 testimony?

6 A Yes, sir.

7 Q Now, in your transactions -- this is the  
8 power Tampa Electric Company sells to other parties.  
9 In your transactions with Hardee Power Partners, for  
10 the first eight months of the year the price  
11 differential between fuel and your total cost is in  
12 the range of 63 to 65 cents a kilowatt hour and then  
13 it jumps -- I misspoke myself. It's .63 cents. And  
14 then for the last four months of this year it jumps to  
15 2.98 cents or \$2.98 cents a megawatt hour. Do you  
16 know the underlying reason for that large increase in  
17 the capacity charge?

18 A You're talking about the Hardee Power sale?

19 Q Look at the Hardee Power sale. It's the  
20 line that says contract.

21 A Right.

22 Q And the fuel cost remains constant but the  
23 total cost jumps up by the amount that I said. Do you  
24 know the reason for that?

25 A Well, one of the reasons could be the Hardee



1 contract, there is an arrangement. There is a  
2 purchase for Tampa Electric -- or sales to Hardee but  
3 then when there's extra capacity on it I believe  
4 that's sold in the wholesale market and it's split  
5 between Tampa Electric and Seminole. So that could be  
6 the reason the fuel cost may vary like that and some  
7 of the months there may be more opportunity to make  
8 wholesale sales.

9 Q And what is the thing that makes it change?

10 A Pardon? The gains would make the total  
11 costs increase and those would be flowed through the  
12 fuel clause.

13 Q I understand that. But what is it that  
14 triggers a higher capacity cost for certain months  
15 than other months?

16 A These aren't capacity costs. These are  
17 energy costs on this schedule. There are no capacity  
18 costs included in this schedule.

19 Q What is the element that constitutes the  
20 difference between fuel cost and total cost?

21 A The gains.

22 Q You don't call it capacity charge or other  
23 charges? You just you call it gain?

24 A Our nomenclature has been to call it the  
25 gains on the sale.

1           Q     And I don't think I understood your  
2 explanation of why the gain is bigger sometimes than  
3 other times.

4           A     Because we have opportunity to make sales.  
5 There are two sales to -- there is one sale, but one  
6 to Seminole if they need it, as well as to if we can  
7 broker it on the market if neither Tampa Electric nor  
8 Seminole needs the energy. So it can be brokered on  
9 the wholesale market and, therefore, you can -- you  
10 know, based on the market pricing there are gains  
11 resulting that are above and beyond the fuel cost.

12          Q     I see. So you were selling power in  
13 September and October to Hardee for resale?

14          A     I don't know if that's the case, but that  
15 could be the reason.

16          Q     All right.

17               MR. MCWHIRTER: That's all the questions  
18 that I have.

19               COMMISSIONER DEASON: Staff still have no  
20 questions?

21               MR. KEATING: No questions.

22               COMMISSIONER DEASON: Okay. Redirect.

23               MR. WILLIS: No redirect. I ask for the  
24 admission of Exhibits 27, 28 and 29.

25               COMMISSIONER DEASON: Without objection



1 Exhibits 27, 28 and 29 are admitted.

2 (Exhibits 27, 28 and 29 received in  
3 evidence.)

4 MR. WILLIS: I call Tom Hernandez.

5 - - - - -

6 THOMAS L. HERNANDEZ

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

10 DIRECT EXAMINATION

11 BY MR. WILLIS:

12 Q State your number and address?

13 A My name is Thomas L. Hernandez. My business  
14 address is 702 North Franklin Street, Tampa, Florida  
15 33602.

16 Q Did you prepare and cause to be prefiled in  
17 this testimony -- in this docket, testimony?

18 A Yes, I did.

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

22 A Yes, they would.

23 MR. WILLIS: I ask that Mr. Hernandez's  
24 direct testimony --

25 WITNESS HERNANDEZ: I do have one change in

1 the direct testimony.

2 Q (By Mr. Willis) Okay.

3 A Page 14, Line 6. The number \$13.5 million  
4 should be \$13.2 million, and this reflects the change  
5 that's in my exhibit. It's a single page document on  
6 that exhibit and this is what drives the change in the  
7 text for the year 2000, 2001. It's the last 14 and a  
8 half months of the FMPA contract. The correct  
9 benefits in 1997 dollars should be \$3,406 in terms of  
10 thousands of dollars and replaces \$3,699. The new  
11 total, therefore, is \$13,248 in terms of thousands of  
12 dollars. And that drove the replacement of the  
13 \$13.5 million that was in the text of my testimony.  
14 So with that change, my testimony is as read.

15 MR. WILLIS: I would ask that  
16 Mr. Hernandez's testimony be inserted into the record  
17 as though read.

18 COMMISSIONER DEASON: Without objection, it  
19 shall be so inserted.  
20  
21  
22  
23  
24  
25

TAMPA ELECTRIC COMPANY  
DOCKET NO. 990001-EI  
FILED: 10/1/99

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

THOMAS L. HERNANDEZ

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

A. My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President-Regulatory Affairs for TECO Energy, Tampa Electric Company's ("Tampa Electric" or "company") parent.

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

A. I graduated from Louisiana State University in 1982 with a Bachelor of Science degree in Chemical Engineering. My responsibilities at Tampa Electric have included engineering and management positions in Production, Generation Planning, Energy and Market Planning, and Fuels and Environmental Services. I was named Vice President-Regulatory Affairs for TECO Energy in March 1998.

1 Q. Have you previously testified before this Commission?

2

3 A. Yes. I testified before this Commission in the last  
4 annual planning hearing Docket No. 910004-EU. I also  
5 provided a description of Tampa Electric's planning  
6 process at the FPSC Staff workshop on March 3, 1994. I  
7 also submitted testimony in Docket No. 930551-EI which  
8 was the numeric conservation goals proceeding for Tampa  
9 Electric. I testified in Docket No. 960409-EI regarding  
10 the prudence of Polk Unit One and, most recently, I  
11 testified in Docket No. 980693-EI regarding the company's  
12 flue gas desulfurization system for Big Bend Units 1 and  
13 2.

14

15 Q. What is the purpose of your testimony?

16

17 A. The purpose of my testimony is to urge the Florida Public  
18 Service Commission ("Commission") to approve a revision  
19 to the current regulatory treatment afforded the  
20 company's existing wholesale power sales agreement with  
21 the Florida Municipal Power Agency ("FMPPA") beginning  
22 January 1, 2000 and ending March 15, 2001, the expiration  
23 date of the agreement. \* As discussed below, this  
24 transaction creates significant net benefits to  
25 ratepayers. While this transaction provides overall net



1        benefits, regulatory treatment of this transaction  
2        imposes a significant loss on the company. Tampa  
3        Electric urges this Commission to approve a revenue flow-  
4        through treatment of this sale, which avoids harming the  
5        company while still providing benefits to customers.  
6        This treatment would begin at the expiration of the  
7        existing rate stipulation agreement approved by Order No.  
8        PSC 96-1300-S-EI ("Stipulation") and would be consistent  
9        with sound regulatory policy as reflected in previous  
10       Commission proceedings.

11  
12       I will also discuss the appropriate regulatory treatment  
13       for the generation-related gains on economy energy  
14       transaction which are short-term, cost-based transactions  
15       between electric utilities. These sales are made either  
16       through the Florida Energy Broker Network ("EBN" or  
17       "broker") or outside the broker. I will also discuss the  
18       appropriate regulatory treatment for transmission revenue  
19       received from such sales not made through the broker.  
20       Finally, I will explain why the Commission should not  
21       eliminate the 20 percent shareholder incentive  
22       established in Order No. 12923, issued January 24, 1984  
23       in Docket 830001-EU-B and why it should consider  
24       additional incentives.

1 Q. Have you prepared an exhibit to support your testimony?

2

3 A. Yes I have. My Exhibit No. 3D (TLH-1) was prepared  
4 under my direction and supervision and consists of one  
5 document.

6

7 Regulatory Treatment for FMPA Wholesale Agreement

8

9 Q. Please describe the FMPA wholesale power supply  
10 agreement.

11

12 A. The FMPA wholesale power supply agreement is a letter of  
13 commitment dated October 2, 1996, as amended by letter  
14 agreements dated November 25, 1997, April 30, 1998, and  
15 October 14, 1998 that provides for long-term interchange  
16 service by Tampa Electric to FMPA in accordance with the  
17 Agreement for Interchange Service dated April 1, 1986, as  
18 supplemented by Service Schedule D (Long-Term Interchange  
19 Service) dated December 20, 1998 ("Agreement"). The  
20 original Agreement provides for the sale of specified  
21 amounts of capacity and associated energy from Tampa  
22 Electric's Big Bend Units 2 and 3, and Gannon Units 5 and  
23 6 from December 16, 1996 through March 15, 2001.

24

25

1 The amounts of contracted capacity made available under  
2 the Agreement ranged from 35 megawatts in 1997 to 105  
3 megawatts through December 15, 1999. For the period  
4 December 16, 1999 through March 15, 2001, the contracted  
5 base capacity will be 150 megawatts. The Agreement  
6 provides that capacity would be available to FMPA any  
7 time generating resources from Big Bend Units 2 and 3,  
8 and Gannon 5 and 6 are available.

9  
10 In March 1998, Tampa Electric began serving FMPA through  
11 third-party resources. The Agreement was formally  
12 amended to reflect that FMPA's capacity needs could be  
13 met with power supplied from third party purchased power  
14 agreements instead of Tampa Electric's generating  
15 resources.

16  
17 Q. Why is making wholesale sales important to Tampa  
18 Electric?

19  
20 A. Making cost effective wholesale sales which provide  
21 revenues greater than incremental costs of making such  
22 sales is good for the company's retail customers as well  
23 as its shareholders. Since its 1985 rate case, when this  
24 Commission gave the company an incentive to keep retail  
25 prices down by increasing wholesale revenues, the company

1 worked hard to optimize those sales. The current and  
2 anticipated levels of such wholesale revenue has been one  
3 of several significant variables that the company has  
4 managed which have resulted in reduced prices to  
5 customers in spite of the pressure of increasing costs.  
6 Retail customers benefit through low prices and  
7 shareholders benefit in the increase in probability of  
8 the company earning its allowed rate of return.

9  
10 Q. Has the Commission provided the company incentives to  
11 enter into transactions like the FMPA sale?

12  
13 A. Yes, most definitely. In the company's 1985 rate order,  
14 the Commission reduced retail revenue requirements by \$37  
15 million based on Tampa Electric's existing sale of  
16 capacity and energy to Florida Power and Light Company.  
17 In that proceeding, the Commission challenged the company  
18 to make up the deficit in revenue requirements by making  
19 up to \$37 million in wholesale sales. The Commission  
20 treated the wholesale sales by allowing the company to  
21 credit 100% of the non-fuel revenue from such sales above  
22 the line in the retail jurisdiction. In 1987, the  
23 Commission approved a proposal by the company to credit  
24 fuel revenues based on the incremental fuel cost from  
25 off-system sales to the retail customer fuel adjustment



1 clause ("Fuel Clause") which had the effect of  
2 encouraging wholesale sales. In the company's 1992 rate  
3 case, the Commission separated certain of the company's  
4 wholesale sales at system average cost, certain others at  
5 unit embedded cost, while still other sales were not  
6 separated from the retail jurisdiction. For some sales  
7 that were not separated from the retail jurisdiction, net  
8 revenues were shared 80/20. There are good, sound policy  
9 reasons for this.

10  
11 Q. What regulatory treatment has the Commission prescribed  
12 for the costs and revenues associated with the Agreement  
13 during the stipulation?

14  
15 A. During the February 1997 fuel adjustment hearing, an  
16 issue was raised regarding cost recovery of non-fuel  
17 revenues associated with sales such as the Agreement.  
18 The Commission opened Docket No. 970171-EU to establish  
19 the regulatory treatment of costs and revenues associated  
20 with such sales. In its Order No. PSC-97-0262-FOF-EI  
21 issued March 11, 1997 the Commission set out its basic  
22 policy with respect to the regulatory treatment for the  
23 recovery of fuel costs of long-term, firm, wholesale  
24 power sales. Under this policy a utility is required to  
25 credit average system fuel costs through the Fuel Clause

1 unless it demonstrates, on a case-by-case basis, that  
2 each new sale provides net benefits to retail ratepayers  
3 in which case incremental costs can be credited.  
4

5 During the hearing conducted in August 1997 in Docket No.  
6 970171-EU, Tampa Electric demonstrated that the sale to  
7 FMPA contributed net present value benefits of \$9 million  
8 (1997 dollars) to the company's retail customers as shown  
9 in my exhibit. In making its decision in this docket,  
10 the Commission concluded that solely because of the terms  
11 of the Stipulation, Tampa Electric was required to  
12 separate the capital and operating and maintenance costs  
13 ("O&M") of the FMPA sales from the retail jurisdiction at  
14 average embedded cost. Furthermore, in light of the fact  
15 that the Commission, in Order No. PSC-97-1273 FOF-EI,  
16 recognized that the FMPA sale provided overall net  
17 benefits to retail ratepayers, the company was permitted  
18 to credit the Fuel Clause and Environmental Cost Recovery  
19 Clause ("ECRC") with revenue amounts equal to the system  
20 incremental fuel and SO<sub>2</sub> allowance costs, respectively,  
21 resulting from the FMPA sale. In the event that fuel  
22 revenues received under the contract were less than the  
23 differential costs for fuel and SO<sub>2</sub>, the company was  
24 ordered to reduce retail operating revenues by the amount  
25 of shortfall.

1 Q. Did Tampa Electric follow the Commission's order for  
2 treating the costs and revenues associated with the FMPA  
3 wholesale power supply agreement?  
4

5 A. Yes. To the extent that Tampa Electric's retail  
6 resources were being used to supply FMPA, from the  
7 inception of the agreement and continuing through  
8 December 31, 1999, Tampa Electric has and will continue  
9 to separate the capital and O&M costs (excluding fuel and  
10 SO<sub>2</sub>) associated with the FMPA sale from the retail  
11 jurisdiction at average embedded costs. In addition,  
12 whenever such retail generating resources were used to  
13 serve the sale the company credited the Fuel Clause with  
14 incremental fuel revenues and credited the ECRC with  
15 incremental SO<sub>2</sub> allowance revenues associated with the  
16 sale as described in the hearing in Docket No. 970171-EU.  
17 (The fuel and SO<sub>2</sub> costs were documented in the company's  
18 1997 and 1998 Fuel Clause and ECRC filings.) Finally, if  
19 there was a shortfall between incremental fuel revenues  
20 and SO<sub>2</sub> revenues and incremental costs, the company made  
21 up the difference with additional credits from retail  
22 revenues.  
23

24 Q. What was the effect of separating the sale at average  
25 system embedded costs?

1  
2 A. This separation treatment resulted in the allocation of  
3 costs that exceeded the non-fuel revenues from the sale  
4 by approximately \$0.7 to \$2.1 million per month. The net  
5 result of this regulatory treatment was that although the  
6 FMPA sale was shown to provide net benefits to  
7 ratepayers, the company was losing approximately \$0.7 to  
8 \$2.1 million per month serving the Agreement.

9  
10 The FMPA sale is an incremental or opportunity sale.  
11 Tampa Electric has no obligation to wholesale customers  
12 to make these kinds of sales and would only do so in  
13 those cases where net benefits accrue to the general body  
14 of ratepayers and the company's shareholders are not  
15 harmed. Separating FMPA sales on an average cost basis,  
16 creates a tremendous disincentive to Tampa Electric to  
17 make these types of sales in the future. The resulting  
18 loss of benefits to our general body of ratepayers under  
19 that treatment would be in no one's best interest.

20  
21 Q. How did Tampa Electric serve the FMPA sale after February  
22 1998?

23  
24 A. In March 1998, Tampa Electric began serving FMPA  
25 partially through third party resources. The third party

resources consisted of purchased power agreements with Florida Power Corporation and PECO Energy Company and by April 28, 1998, the total amount of third-party supplied purchase power equaled the entire amount of contracted capacity to be supplied to FMPA under the Agreement. Therefore, since April 28, 1998, none of Tampa Electric's generating units have been used to serve the sale.

Q. How did Tampa Electric treat the costs and revenues associated with the FMPA wholesale power supply agreement after February 1998?

A. In every month that Tampa Electric was not serving FMPA directly from its own generating resources, the purchase power costs and sales revenues were excluded from the retail jurisdiction. The amount of energy required to serve the FMPA sale equaled the amount of energy purchased from third-party suppliers. Therefore, in each of those months the FMPA sale was served totally by third-party purchases and the fuel cost recovery factor was not affected in any way.

Q. Why is Tampa Electric seeking different regulatory treatment for the FMPA wholesale power supply agreement for the period of January 1, 2000 through March 15, 2001?

- 1  
2 A. When the Commission made its decision in Order No. PSC-  
3 97-1273-FOF-EU, it established the regulatory treatment  
4 for the duration of the Stipulation or through December  
5 31, 1999. During its discussion at the agenda conference  
6 when the decision was made, the Commission made it clear  
7 that Tampa Electric could seek alternative treatment  
8 after the Stipulation ended. We are now requesting  
9 different treatment since the benefits to ratepayers far  
10 exceed those contemplated in the original economic  
11 benefit analysis with Tampa Electric forced to make up  
12 this difference at a substantial loss to shareholders.  
13
- 14 Q. What is Tampa Electric's proposed treatment for the FMPPA  
15 wholesale power supply agreement for the period January  
16 1, 2000 through March 15, 2001?  
17
- 18 A. The company is proposing a revenue flow-through treatment  
19 that credits all revenues received from the FMPPA sale to  
20 retail customers through the ECRC and Fuel Clause. The  
21 company will credit the ECRC with revenues to offset the  
22 incremental SO<sub>2</sub> costs. The SO<sub>2</sub> allowance costs will be  
23 determined by using the market price for SO<sub>2</sub> allowances  
24 and the weighted average SO<sub>2</sub> emission rate for Big Bend

1 Units 2 and 3 and Gannon Units 5 and 6. All remaining  
2 revenues will be credited to the Fuel Clause.

3  
4 Q. Why is this proposed treatment appropriate?

5  
6 A. The proposed FMPA treatment provides customers benefits  
7 derived from this type of wholesale sale, and eliminates  
8 the absolute disincentive that is created by the  
9 separation treatment required during the Stipulation.  
10 Tampa Electric's proposed regulatory treatment of the  
11 Agreement is fair and reasonable, and sends an  
12 appropriate signal rather than discouraging utilities  
13 from seeking future opportunities to reduce their costs  
14 of providing service.

15  
16 Q. What are the overall total benefits for retail ratepayers  
17 resulting from the FMPA agreement?

18  
19 A. The appropriate way to review the overall total benefits  
20 of the Agreement is to review what was known and  
21 reasonably assumed at the time the Agreement was signed.  
22 As stated above, and shown in my exhibit, the company  
23 originally projected net present value benefits of \$9  
24 million (1997 dollars) for the contract period. These  
25 benefits were determined based upon a cost benefit

1 analysis of this wholesale power transaction during the  
2 period 1997 through 2001. In evaluating the benefits  
3 realized from the current regulatory treatment and those  
4 benefits to be obtained under the proposed regulatory  
5 treatment from January 1, 2000 through the end of the  
6 Agreement, the company has determined that \$13.<sup>2</sup>/<sub>8</sub> million  
7 (1997 dollars) net benefits will be achieved as shown in  
8 my exhibit.

9  
10 Q. Why should the Commission approve your proposed  
11 regulatory treatment of the FMPA sale?

12  
13 A. It should be approved as a matter of sound regulatory  
14 policy consistent with the Commission's Order in Docket  
15 No. 970171-EU as well as a matter of basic fairness. The  
16 proposed regulatory treatment will provide additional net  
17 benefits for the remainder of the contract and these  
18 benefits will be passed through to customers without  
19 penalizing the company. The separation treatment based  
20 upon average embedded costs imposed during the Agreement,  
21 on the other hand, does in effect provide a severe  
22 penalty to the company.

23  
24 It is simply unreasonable and unfair to continue to  
25 require a regulatory treatment which provides a financial



1 penalty and disincentive for entering into a transaction  
2 which has reasonable expectations of providing net  
3 benefits to customers. The reason separation was  
4 required initially was related to the Stipulation. The  
5 Stipulation term ends December 31, 1999 and accordingly  
6 separation treatment should end.

7  
8 Economy Sales Transactions

9  
10 Q. Please describe the appropriate regulatory treatment for  
11 generation costs associated with economy sales?

12  
13 A. For generation costs, revenues sufficient to cover the  
14 fuel costs associated with Schedules C and X transactions  
15 are credited through the Fuel Clause and revenues  
16 sufficient to cover the associated SO<sub>2</sub> credits are  
17 credited through the ECRC. Revenues are also credited to  
18 operating revenues to cover incremental variable O&M  
19 costs incurred by the company.

20  
21 Q. How are the gains from economy energy sales treated for  
22 regulatory purposes?

23  
24 A. Gains are realized by the company selling the energy as a  
25 result of the "split the savings" methodology used to

1 calculate the transaction price of economy energy. The  
2 gain is simply the difference between the transaction  
3 price and the associated incremental fuel, O&M and SO<sub>2</sub>  
4 costs of the seller. This Commission has long had a  
5 policy of encouraging these transactions by providing  
6 incentives for the utilities to engage in economy sales.  
7 On January 24, 1984, the Commission entered its Order No.  
8 12923, Docket No. 830001-EU-B authorizing utilities to  
9 retain 20 percent of their gains on economy sales while  
10 providing net benefit to ratepayers. In its order the  
11 Commission agreed with Staff witness testimony that a  
12 positive incentive is desirable for the purpose of  
13 maximizing the benefits of the Energy Broker Network:  
14 "We believe Staff's witness was correct in stating that  
15 "a positive incentive will preserve current levels of  
16 economy sales and may result in increased sales and that  
17 a 20 percent incentive is large enough to maximize the  
18 amount of economy sales and provide a net benefit to  
19 ratepayers." The Supreme Court of Florida affirmed the  
20 Commissions position in Citizens v. Public Service  
21 Commission, 464 So 2d 1194 (Fla. 1985). It was clear  
22 both then and now that the Commission provided an  
23 incentive to engage in economy sales type transactions.

1 Q. What is the appropriate regulatory treatment for the  
2 generation-related gain on Schedule C and X transactions  
3 not made through the broker?  
4

5 A. The treatment should be the same as if it were made  
6 through the broker. The broker is merely a computerized-  
7 based, telephonically-linked, system driven by hardware  
8 and software. In essence, it is a tool that facilitates  
9 Schedule C transactions for those utilities that wish to  
10 use the system. There is no logical reason for making  
11 any distinction between types of economy sales based  
12 solely on the type of tools used by the buyer and seller  
13 to communicate their offers and document the  
14 transactions. Any generation-related gains associated  
15 with economy sales transactions should be treated the  
16 same way whether the broker is used or not since the  
17 policy of incenting such transactions clearly should  
18 apply to both broker and non-broker transactions.  
19 Accordingly, eighty percent of those gains assigned to  
20 the retail jurisdiction should be credited to ratepayers  
21 through the fuel clause. The company should retain 20  
22 percent of the gain from a non-broker transaction.  
23  
24  
25

1 Q. What is the appropriate regulatory treatment for  
2 transmission revenues received from non-separated economy  
3 sales?

4  
5 A. Transmission revenues from economy sales should be  
6 separated on an energy basis. Eighty percent of those  
7 revenues should be credited to retail ratepayers through  
8 the Fuel Clause. The company should retain the remaining  
9 20 percent.

10  
11 Q. Should the Commission eliminate the 20 percent  
12 shareholder incentive set forth in Order No. 12923,  
13 issued January 24, 1984 in Docket No. 830001-EU-B?

14  
15 A. Definitely not. In fact the Commission should increase  
16 the incentive to give greater encouragement to utilities  
17 to enter into these types of transactions. Elimination  
18 of the 20 percent shareholder incentive will negatively  
19 impact both sellers and purchasers since fewer  
20 transactions will occur in the absence of incentives.  
21 The shareholder incentive encourages sellers to offer  
22 their as-available energy within the state and provides  
23 mutual benefits for customers of both sellers and buyers.

24  
25

1 Q. Why should utilities be incented to ensure there are  
2 mutual benefits for customers of both sellers and  
3 purchasers of energy?

4  
5 A. Utilities should be incented to carry reserve margins in  
6 excess of their minimum planning margins to serve two  
7 purposes: one is to meet contingency needs of the state  
8 when individual and statewide loads are higher than  
9 expected due to extreme weather conditions or when  
10 generating unit availability is less than expected. The  
11 second purpose is to balance the market and business risk  
12 of those utilities that depend on the market for  
13 reliability purposes with those utilities that help meet  
14 market needs. It is appropriate for the Commission to  
15 provide incentives to utilities that have acknowledged  
16 the need for additional capacity and have modified their  
17 resource plans accordingly. Particularly, when such  
18 incentives will maximize benefits to their retail  
19 customers.

20  
21 Q. Please summarize the appropriate regulatory treatment for  
22 the generation-related gains on economy energy  
23 transactions, the appropriate regulatory treatment for  
24 transmission revenues received from economy sales, and

1        why the Commission should not eliminate the 20 percent  
2        shareholder incentive.

3  
4        A.    Tampa Electric enters into hourly or multi-hour, cost-  
5        based, "split the savings" economy wholesale energy  
6        transactions. These transactions can be made utilizing  
7        the broker or not utilizing the broker. The transactions  
8        result in "share the savings", of which eighty percent of  
9        the energy-based generation gains and transmission  
10       revenues are returned to ratepayers as a credit to the  
11       Fuel Clause. The remaining 20 percent is retained by the  
12       company. The 20 percent is critical in incenting and  
13       benefiting sellers, purchasers and ratepayers. Both  
14       sellers and buyers are able to offset and reduce fuel  
15       costs to ratepayers with sellers retaining a portion of  
16       the gains within the company. The Commission should  
17       seriously consider enhancing incentives for those  
18       utilities willing to provide generation resources to  
19       serve the needs of its ratepayers and the Florida market  
20       due to unexpected slumps in supply-side resources and/or  
21       customer demand. Therefore, although the wholesale  
22       market has changed considerably over the past few years,  
23       the incentives continue to serve an important purpose and  
24       continue to send a correct and positive message to  
25       wholesale market participants.

1

2 Q. Does this conclude your testimony?

3

4 A. Yes, it does.

5

6

7

8

9

10

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25

1           **MR. WILLIS:** We request that his exhibit, as  
2 he has corrected it, be marked.

3           **COMMISSIONER DEASON:** It should be  
4 identified as Exhibit 30.

5           (Exhibit 30 marked for identification.)

6           **Q**       **(By Mr. Willis)** Please summarize your  
7 testimony.

8           **A**       Good morning, Commissioners. My direct  
9 testimony in this proceeding supports Tampa Electric's  
10 proposed regulatory treatment of its wholesale power  
11 supply agreement with the Florida Municipal Power  
12 Agency or sometimes referred to as FMPA for the period  
13 January 1, 2000 through March 15, 2001.

14           This Commission has a policy relating to  
15 long-term firm wholesale power sales that requires a  
16 utility to separate production plant and operating  
17 expenses associated with the sale from the retail  
18 jurisdictions cost responsibility unless the utility  
19 shows on a case by case basis that the sale generates  
20 net benefits to retail customers in which case  
21 separation is not required and the revenues of the  
22 sale are flowed through the fuel adjustment clause.  
23 Tampa Electric made such a demonstration in a hearing  
24 conducted with this Commission in August 1997. We  
25 showed then that the sale to FMPA contributes net



1 present value benefits of approximately \$9 million in  
2 1997 dollars to the company's retail customers.  
3 However, because of the existence of a rate  
4 stipulation entered into between Tampa Electric, FIPUG  
5 and OPC, the Commission required Tampa Electric to  
6 separate the FMPA sale at average system embedded  
7 costs. This separation treatment resulted in the  
8 allocation of the costs that exceeded the nonfueling  
9 revenues from the sale by approximately \$700,000 to  
10 \$2.1 million per month; a direct loss to the company  
11 even though the FMPA sale was shown to provide net  
12 benefits to our ratepayers.

13 When the Commission made that decision it  
14 was made clear that Tampa Electric could seek  
15 alternative treatment after the stipulation ended. We  
16 are now proposing such treatment that will continue to  
17 benefit our customers and at the same time avoid a  
18 substantial loss to the company since the stipulation  
19 ends December 31st of this year.

20 Our proposal is simply to flow back 100% of  
21 the total revenues received from FMPA back to retail  
22 customers through the fuel and environmental cost  
23 recovery clauses. The proposed FMPA treatment  
24 provides our customers with benefits derived from this  
25 sale and eliminates an absolute disincentive created

1 by the separation treatment required during the  
2 stipulation.

3 Our proposed regulatory treatment is both  
4 fair and reasonable, particularly since the projected  
5 benefits to customers from this agreement is  
6 approximately \$4.5 million dollars higher than the  
7 original \$9 million estimate in terms of benefits  
8 projected back in the 1997 proceeding.

9 We urge you to approve our proposed  
10 regulatory treatment as a matter of basic fairness.  
11 It will provide additional net benefits to our  
12 customers and at the same time curtail a severe  
13 penalty to Tampa Electric.

14 My direct testimony also describes the  
15 appropriate regulatory treatment of gains from economy  
16 energy sales which Tampa Electric defines as Schedule  
17 C and Schedule X sales. This Commission has a long  
18 standing policy of encouraging these transactions by  
19 providing incentives for the utilities to engage in  
20 economy sales transactions.

21 The 80/20 split of gains on economy sales  
22 was instituted by this Commission in 1984 with the  
23 Commission agreeing with Staff that positive  
24 incentives are desirable for purposes of maximizing  
25 economy sales transactions. This incentive is

1 appropriate for all economy sales whether they are  
2 made on or off the Florida energy broker network  
3 commonly referred to as the broker. There simply is  
4 no basis for differentiating between the two  
5 transactions because the broker is merely a  
6 computerized tool that facilitates Schedule C and X  
7 transactions. The nature of this transaction is the  
8 same. Transmission revenues and generated related  
9 gains from economy sales should be separated on an  
10 energy basis and shared by retail ratepayers in the  
11 company on the same 80/20 basis.

12 Finally, my testimony urges the Commission  
13 not to eliminate the 20% shareholder incentive the  
14 Commission adopted in 1984. Such an action would  
15 negatively impact both sellers and purchasers of  
16 short-term energy within Florida. This incentive  
17 encourages utilities that may otherwise not do so, to  
18 sell energy within this state and help improve overall  
19 Peninsular Florida reliability as well as economics.  
20 If any change at all is made with respect to  
21 incentives the incentives should be expanded to cover  
22 all types of off system sales. Although the wholesale  
23 market has changed considerably over the past few  
24 years, the incentives continue to serve an important  
25 purpose and this incentive continues to send a correct

1 and positive message to wholesale market participants.  
2 To remove the incentive on economy sales would be the  
3 exact opposite action that the Commission should take  
4 in this proceeding. That concludes my summary.

5 MR. WILLIS: Tender the witness.

6 COMMISSIONER DEASON: Mr. McWhirter.

7 CROSS EXAMINATION

8 BY MR. MCWHIRTER:

9 Q Mr. Hernandez, you're aware that FIPUG has  
10 filed a position in this case that the FMPA sale  
11 continue to be separated, is that -- you're aware of  
12 that?

13 A Yes, I am.

14 Q And I'd like to ask you some questions about  
15 the FMPA sale, if I may. This contract lasts for one  
16 more year and three months?

17 A Technically, it's one year and two and a  
18 half months. The contract ends March 15, 2001.

19 Q Will this contract be continued or will it  
20 be terminated and the capacity that's dedicated to  
21 that contract returned to the use of your retail  
22 customers at the conclusion of the contract?

23 A This contract or purchase or sales agreement  
24 concludes at the end of the day on March 15, 2001.

25 Q I understand that it ends. My question is,

1 are you aware of whether the intention of your company  
2 is to continue it beyond that date?

3 A No, I am not aware of that intent.

4 Q Okay. As I understand your testimony in  
5 this case, every dime that is collected under that  
6 contract will be flowed directly through to retail  
7 customers through the cost recovery clauses; is that  
8 correct?

9 A Yes, specifically the fuel and environmental  
10 cost recovery clauses.

11 Q If we have a separation of that sale after  
12 January 1st, you would be required to pay average fuel  
13 costs but Tampa Electric would keep the rest of the  
14 money?

15 A We would effectively -- if we separated we  
16 would effectively take the approximately \$44 million  
17 of revenues that we're proposing to credit and keep  
18 100% of those revenues and then credit back to the  
19 fuel clause the cost associated with serving that sale  
20 out of those assigned units, that's correct.

21 Q So it would -- it appears to me after asking  
22 you these questions and after looking at your  
23 deposition, that although our philosophy is in favor  
24 of separating contracts for more than one year -- that  
25 are of more than one year duration, in this particular

1 case customers will be better off for the duration of  
2 this particular contract if it is not separated?

3 A That's correct.

4 Q All right. Actually, I was making a  
5 statement there for the record.

6 A I'm agreeing with you.

7 MR. MCWHIRTER: But I want to tell the  
8 Commission, we've addressed this issue and we  
9 conclude, after giving it thorough study, that  
10 although it's philosophically against what we like to  
11 see monetarily on this specific case at this specific  
12 time the customers are better off and we're going to  
13 withdraw our objection to the separation aspect.

14 However, we don't want to leave  
15 Mr. Hernandez at peace on that subject. Our concern  
16 is principally with capacity available and a lot of my  
17 clients are nonfirm customers who have been  
18 interrupted and for whom purchased power was purchased  
19 this year.

20 Q (By Mr. Mcwhirter) If the FMPA contract  
21 was separated we would still not have that capacity  
22 available for your nonfirm load, would we?

23 A That's correct.

24 Q But if the contract is not continued we will  
25 have it after March of 2001?

1           A     After March 15th year 2001, that's correct.

2           Q     Now, you enter into a variety of sales.  
3     You've already committed 150 megawatts to the FMPA  
4     transaction and you've committed 145 megawatts to  
5     first call on the Big Bend facilities, and with  
6     respect to the Hardee Power Station, Seminole has  
7     first call on all the capacity that's in place up to  
8     date but not the new capacity you're going to --  
9     you're talking about in this case; is that correct?

10          A     I'll say yes, but it's qualified and let me  
11     qualify the sale. The Big Bend 4 sale, the 145  
12     megawatt sale to Seminole, which ends year 2003, is  
13     capped by an energy. It is not restrictive of the  
14     capacity. There is a restriction in terms of the  
15     actual usage of that capacity and that was  
16     predescribed in the original agreement that was set in  
17     place or became effective January 1, 1993.

18                 On the Hardee capacity that Mr. McWhirter  
19     was referring to, the original agreement had a sale  
20     from Hardee Power Partners to Tampa Electric and to  
21     Seminole Electric and this was the shared resource  
22     concept. The capacity is available to Seminole only  
23     to the extent that they have unavailable capacity  
24     associated with Seminole 1 and Seminole 2 in a --  
25     there are 14 megawatts allocation of Crystal River 3,

1 the nuclear plant for FPC.

2           If those three resources are up and running,  
3 then all of that capacity, the 295 megawatts nominal  
4 rating at the Hardee facility is available first to  
5 Tampa Electric. And then to the extent that -- as was  
6 discussed before by Ms. Zwolak, to the extent that  
7 neither Tampa Electric nor Seminole needs it for its  
8 own native system requirements, it is then given back  
9 to Hardee Power Partners to sell on the market. And  
10 then to the extent that there's any gains from those  
11 sales, 40% of the gains goes to Tampa Electric's  
12 customers, 60% of the gains goes to Seminole  
13 customers. So it's a qualified availability of that  
14 capacity, both Big Bend 4 and the Hardee capacity.

15           The newest purchased power, the Hardee CT-2B  
16 purchase, which was considered in the original  
17 agreement, does have a different configuration. In  
18 this case, there is no restriction by Tampa Electric  
19 in terms of access to the capacity. There's no  
20 requirement or contingency that if Seminole 1 or  
21 Seminole 2 or Crystal River 3 were down, Tampa  
22 Electric still has the first call on that capacity.  
23 So there is no contingency requirement on that. So  
24 that is a subtle difference in the agreement. That  
25 was agreed to by Seminole Electric and Tampa Electric



1 as well as Hardee Power Partners in this new contract.

2 Q Let me see if I can summarize your response  
3 to my last question. My question was, with respect to  
4 145 megawatts of Big Bend 4, if Tampa Electric's  
5 retail customers had a need for the power and Seminole  
6 claimed that power, which one would have priority?

7 A If the energy allocation on Big Bend 4 was  
8 used up, Tampa Electric would. If there was still  
9 energy remaining up to the cap then Seminole Electric  
10 could take that capacity.

11 Q All right. If it hadn't consumed the  
12 appropriate amount of energy from it?

13 A That's correct.

14 Q All right. Now, with respect to -- what is  
15 the present size of the Hardee Power Plant? Is it --

16 A It's nominal rated 295 megawatts, and that's  
17 comprised of Unit 1, which is a combined cycle unit.  
18 Has a nominal rating of 220 megawatts. CT-2A, which  
19 is the first CT set up for the second combined cycle,  
20 if built, has a nominal rating of 75 megawatts. So  
21 that comprises 295 megawatts.

22 Q With respect to that 295 megawatts, if Tampa  
23 Electric has a need for the power and Seminole has a  
24 need for the power, which one gets it?

25 A Tampa Electric would unless Seminole 1 or

1 Seminole 2 are forced outage or planned outage.

2 Q Are you familiar with the petition that your  
3 company filed with the Federal Energy Regulatory  
4 Commission?

5 A In what matter?

6 Q In the approval of the new contract in which  
7 it stated the background of the old contracts?

8 A I did not review the contract, but my  
9 understanding is the contract was submitted to FERC  
10 and it was approved by FERC.

11 Q If you have not examined the contract, are  
12 you absolutely sure that Seminole does not have a  
13 first claim on that Hardee capacity irrespective of  
14 whether its other plants are down?

15 A I'm sure, based on discussions I've had with  
16 other officers at Tampa Electric.

17 Q But you haven't examined the contract  
18 yourself?

19 A No, I did not read the contract in detail.

20 MR. MCWHIRTER: Mr. Chairman, I'd like to  
21 request a late-filed exhibit in this case. I didn't  
22 think this would come up but the late-file exhibit  
23 would be the petition filed by Hardee Power Partners  
24 with the Federal Energy Regulatory Commission in  
25 which, as a background, the petitioners explained the

1 relationship between Tampa Electric and Seminole with  
2 respect to claims on that capacity.

3 MR. WILLIS: Commissioner, that petition is  
4 attached to Mr. Brown's testimony.

5 MR. MCWHIRTER: Good.

6 COMMISSIONER DEASON: There's no need for a  
7 late-filed exhibit then.

8 MR. MCWHIRTER: I was looking for it a  
9 minute ago. If it's attached to Mr. Brown's  
10 testimony, I didn't see it.

11 MR. WILLIS: It's attached to his rebuttal  
12 testimony.

13 MR. MCWHIRTER: Would you furnish me with a  
14 copy of it please?

15 MR. WILLIS: Commissioner, any further  
16 questions with respect to this should be addressed to  
17 Mr. Brown who testifies on this subject. I've given  
18 Mr. McWhirter some latitude to inquire into a subject  
19 that was not covered in Mr. Hernandez's direct  
20 testimony.

21 MR. MCWHIRTER: I will accept that offer.  
22 I've got what I want now, but obviously Mr. Brown  
23 would be more familiar with it than Mr. Hernandez.

24 COMMISSIONER DEASON: Very well.

25 Q (By Mr. McWhirter) In your deposition in

1 this case, Mr. Hernandez, you were asked questions  
2 about your various types of sales and you mentioned a  
3 variety, Schedule A, B, C, X. I don't think you  
4 mentioned L but you mentioned J.

5 A D and Js, that's correct.

6 Q And J are not -- are wholesale nonfirm sales  
7 that are made on the spot market to gain the  
8 opportunities that are available to you at that time.  
9 The concern that I have with respect to those sales is  
10 the relationship and priority between the wholesale  
11 nonfirm customer and the retail nonfirm customer.  
12 When you entered into a contract like that, which of  
13 those customers has priority?

14 A Just to clarify, Schedule Js, by the way  
15 Tampa Electric has used Schedule Js in the past, could  
16 be firm or nonfirm. They are negotiated sales. We  
17 don't consider them as a economy type transactions.  
18 Schedule Js are typically one year or less. We've  
19 entered into transactions that could be recallable.  
20 We've entered into transactions that are firm. And a  
21 lot of that judgment depends upon what's happening in  
22 the market, what our available resources are to serve  
23 that sale, and so it's a qualified circumstantial type  
24 situation where it depends on what our supply and  
25 demand resource issue is whether or not we make a firm

1 or nonfirm.

2 Q All right. Now, that you've explained that,  
3 would you answer my question, which is, if you have a  
4 Schedule J nonfirm sale and you have a nonfirm retail  
5 customer, which of those customers takes priority in  
6 the event that you have a forced outage of your other  
7 equipment and you need the power and you won't have  
8 enough power to serve both contracts?

9 A Since you characterize it as a nonfirm  
10 transaction, I believe we would serve our retail  
11 requirements -- total retail. We do have the ability  
12 related to nonfirm customer to exercise load  
13 management. We have a provision in our tariff that I  
14 believe it was sometime in the early 90's that we  
15 modified that tariff to allow us to use that as a  
16 resource if there were -- to realize opportunity  
17 sales. We don't do that often. We do not have that  
18 same capability in our interruptible tariff.

19 Q All right. Let me ask you the question  
20 perhaps another way. You have a Schedule J  
21 opportunity sale that's made on Wednesday for a  
22 Thursday delivery. On Thursday morning you have a  
23 power outage. You don't have enough power to serve  
24 that Schedule J sale but you do have enough power to  
25 serve all your retail firm load, but you don't have

1 enough power if you serve the Schedule J to serve your  
2 interruptible customers. Would the Schedule J be  
3 served or would the interruptible customers be served?

4 A My understanding is that a nonfirm  
5 Schedule J would be recalled so that we can serve the  
6 interruptible customers.

7 Q All right. Are you absolutely certain that  
8 that's your company's position? It would give us  
9 comfort to have that under oath in this case.

10 A I'm not involved with the day to day  
11 transactions, so to the best of my knowledge I would  
12 say that that's what we would do.

13 Q All right. And are you a stater of company  
14 policy that -- to bind your company on a thing like  
15 that?

16 MR. WILLIS: Commissioner, I'm going to  
17 object to further lines of questions. This -- along  
18 this line. This is outside the scope of  
19 Mr. Hernandez's direct testimony. It's not on any  
20 issue that's pending before --

21 COMMISSIONER DEASON: I will sustain the  
22 objection. The witness has answered the question to  
23 the best extent that he has.

24 MR. MCWHIRTER: All right.

25 Q (By Mr. Mcwhirter) I'd look to go on to

1 your testimony with respect to incentives. You get  
2 an -- customers get 80% of your nonseparated sales and  
3 the company gains 20%. And I would ask you if there  
4 may not be some other incentives. When you generate  
5 electricity I understand that the generators use fuel  
6 to do that, they burn coal?

7 A Is that a question?

8 Q Yes. Is that correct?

9 A Yes. In order to generate electricity we  
10 need to consume fuel.

11 Q Now, does Tampa Electric have an affiliated  
12 coal company that sells coal to Tampa Electric  
13 Company?

14 A We do. This is the last year of that  
15 contract. Very small amount of coal.

16 Q Does that company make a profit when it  
17 sells coal?

18 A I wouldn't know what their profit is.

19 Q You wouldn't -- I didn't ask you the amount  
20 of the profit. Is it in the general business design  
21 that it makes a profit on the sale of coal?

22 A I will hope that there would be some type of  
23 profit margin.

24 Q Now, Tampa Electric owns a lot of barges  
25 that transport coal. Do those barges make a profit

1 when they transport the coal from the mines down to  
2 Florida?

3 A Again, I don't know what the amount would be  
4 but I would assume there would be some type of margin.

5 Q All right. Now, as I understand it, Tampa  
6 Electric has a trading room in which you have  
7 employees who engage in these wholesale transactions,  
8 opportunity transactions. Do those people receive any  
9 kind of brokerage fee for making the sale?

10 A I don't know.

11 Q If they did and if the fuel company made  
12 profit on fuel and if the transportation company made  
13 a profit on the transportation, would it not be fair  
14 to say that there is, in fact, an incentive to the  
15 parent corporation for these sales to be made?

16 A That's a difficult question to answer  
17 because, as we've talked before, there's an issue  
18 about the balance of supply and demand and having the  
19 resources available to make these short-term  
20 opportunity sales that you're talking about. Just to  
21 clarify something you said in the beginning and then  
22 I'll get back to what you just asked me.

23 The 80/20% split is only made on the economy  
24 sales transactions. There are other nonseparated  
25 transactions like the Schedule J that 100% of those



1 benefits or margins go back. I think that's something  
2 for the Commission to consider in terms of opening up  
3 the incentives to other types of sales.

4 But at this time, what Tampa Electric has  
5 done and what's in our current projection, the 20%  
6 margin share that goes back to the shareholders only  
7 applies to the Schedule C and X transactions.

8 The scenario you're setting up related to  
9 other additional incentives for moving more fuel or  
10 burning more fuel, that really from a business  
11 planning perspective opportunity sales are just that.  
12 They're not a firm commitment to make the transaction.  
13 We're not obligated to continue those transactions if  
14 we enter into them. They are simply opportunity or as  
15 available sales.

16 So for any one of our operating companies to  
17 plan on that as a firm transaction, that's not what we  
18 do. We do not assume that we're going to be able to  
19 make these opportunity sales. We make an estimate  
20 related to business planning purposes but there is no  
21 guarantee. It's subject to our retail load. It's  
22 subject to our unit or resource availability. And  
23 also a willing market; a market that would support  
24 entering into a wholesale transaction.

25 So it's difficult to say if that really

1 truly is an incentive for us from a corporate point of  
2 view.

3 Q Thank you for that explanation. You heard  
4 Ms. Zwolak testify that she thought it was a fair  
5 estimate without independent calculation that 65% of  
6 your fuel cost is incurred in the summer months and  
7 35% in the winter months. If Mr. Taylor's hypothesis  
8 is correct that setting one fuel factor that charges  
9 more than actual cost during the off peak period and  
10 less for fuel cost during the on peak period, would  
11 Tampa Electric be opposed to providing an optional  
12 seasonal rate that closely tracked costs in each  
13 season? For instance, one that would cover the eight  
14 off shoulder months -- I mean, the eight shoulder  
15 months and one that would cover the four peak months?

16 A Just the way you started that out in terms  
17 of the percentages, I would have to subject to check  
18 on what that allocation of cost and what that  
19 relationship of costs and energy is. But,  
20 conceptually, Tampa Electric would consider developing  
21 a seasonal, if you will, on-peak off-peak seasonal  
22 rate patterned similarly to the time of day rate as  
23 reflected in concept Schedule -- I think it's Schedule  
24 E1-D of Ms. Zwolak's exhibit.

25 And the concept there, there's a one page in

1 her exhibit. The concept there is that you walk  
2 through using the levelized fuel factor on an annual  
3 basis and you simply would make an offering that based  
4 on energy consumption and production costs, along the  
5 lines of higher costs and higher energy over the  
6 summer months versus lower production costs and lower  
7 energy usage generally over the winter months, at  
8 least this is true for our system, and you can come up  
9 with a relationship of cost and usage related to the  
10 summer season, the four months that were discussed  
11 yesterday, May, June, July and August, relative to the  
12 other months of the year.

13 So conceptually, we would consider  
14 developing a seasonal time of use or seasonal  
15 utilization rate that keys off the existing projected  
16 levelized annualized fuel cost recovery factor, but  
17 effectively once we did the math I would envision that  
18 you'd have a scaler, a multiplier if you will, greater  
19 than one for the summer months and a scaler less than  
20 one for the winter months. And that conceptually is  
21 similar to the concept of an on-peak off-peak rate.

22 If you look at the schedule in Ms. Zwolak's  
23 exhibit you'll see that the factor for on-peak usage  
24 to better reflect the on-peak production cost is  
25 higher than the levelized factor and that the off-peak

1 factor is somewhat less than that.

2 So conceptually what Tampa Electric would  
3 consider is develop a seasonal rate patterned off the  
4 same concept.

5 Q If you did such a rate it would be cost  
6 based and it wouldn't discriminate against any other  
7 customers, would it?

8 A That's correct, because we're still taking  
9 the same system projected cost. It would be an  
10 optional type program. It would have to consider at  
11 some time the mechanics of running through the  
12 numbers, but conceptually it seems reasonable to be  
13 able to develop an offering like that.

14 Q So if a company or a customer desired to  
15 have a flat rate for budgeting purposes they could  
16 have that, but if someone wanted to adjust their  
17 consumption pattern so that they could take advantage  
18 of the seasonal rate they could do that as well?

19 A That's correct. I would envision this  
20 almost like a passive conservation program; the price  
21 elasticity issue. The higher the price, the less  
22 likely you would use to the extent you can modify your  
23 consumption behavior and shift usage from the summer  
24 to the winter if a customer could do so. And it's the  
25 same concept in the on-peak off-peak rate.

1           Q     Could you do that before the beginning of  
2 this new era, collection?

3           A     Resources as they are, what we would try to  
4 do -- what we would do is put together a filing for  
5 this Commission on or before January 1st, subject to  
6 Commission review and approval, and what I'd like to  
7 do is consider it as maybe a pilot program to see what  
8 kind of market penetration we would have.

9                     But effectively once we run the numbers,  
10 bring it back to this Commission, and subject to your  
11 review and approval. And to the extent that you're  
12 willing to allow us to have this pilot program, we  
13 would be willing to enter into that and allow  
14 customers to try a seasonal rate.

15           MR. MCWHIRTER: I tender the witness.

16           COMMISSIONER DEASON: Mr. Burgess.

17                     CROSS EXAMINATION

18           BY MR. BURGESS:

19           Q     Mr. Hernandez, I have some questions about  
20 the FMPA sale. Is it correct that at this point that  
21 TECO has found another source to supply that  
22 particular agreement; to supply the energy associated  
23 with that particular agreement?

24           A     Just to clarify, when you say at this point,  
25 do you mean for this year or for next year?

1           Q     For this year. Let's start with 1999.

2           A     For 1999, that's correct. 100% of the  
3 resources used to serve the sale are from third party  
4 purchases.

5           Q     Is that a single third party?

6           A     No, there's two parties.

7           Q     Can you tell me who they are?

8           A     PECO Energy and Florida Power Corporation.

9           Q     What's the treatment, the fuel adjustment  
10 treatment for that for the cost and revenues  
11 associated with that at this point?

12          A     There are no costs associated with the sale  
13 or the purchases in the fuel adjustment filings.

14          Q     Is -- if for some reason either PECO or  
15 Power Corp. or both were unable to meet their  
16 obligations under the sale, is Tampa Electric still  
17 obligated to meet some portion of it or to meet the  
18 requirements of the FMPA sale?

19          A     To the extent there was a shortfall, we  
20 would either utilize one of our assigned resources or  
21 have an additional short-term third party purchase to  
22 cover, but that has not been the case to date.

23          Q     But the answer is, yes, contractually you're  
24 still under the obligation to be the guarantor of this  
25 energy; is that correct?

1           **A**     That's correct, with the option to either  
2     utilize our resources or third party purchases.  
3     That's correct.

4           **Q**     Okay. Now, as I understand it, what you're  
5     saying with regard to the year 2000 is your -- Tampa  
6     Electric would like to the Commission to adopt the  
7     proposition that the entirety of the revenue go  
8     through fuel adjustment as revenue credit and fuel  
9     adjustment; is that correct?

10          **A**     With the slight change, that's correct. The  
11     portion -- a small portion of that -- those revenues  
12     would be credited through the environmental cost  
13     recovery clause.

14          **Q**     And is the \$44 million that you gave, is  
15     that the sum of the amount that would go through fuel  
16     adjustment and environmental?

17          **A**     That's correct, for the full 14 and a half  
18     months of the transactions.

19          **Q**     For the full 14 and a half months. Okay. I  
20     would like to understand the dollar impact of the  
21     other changes that TECO would like and so I want to  
22     stay on consistent ground; either the entire 14 and a  
23     half months or the 12 months of the year 2000. Do you  
24     have the amount that would be associated with the full  
25     14 and a half for the other aspects of this or would

1 it be better to run them through as an annualized  
2 figure for the year 2000?

3       **A**     I believe I have it. I can answer questions  
4 in both ways. The confusion is, we're seeking the  
5 regulatory treatment for the 14 and a half months so  
6 this won't be as much of an issue in the next fuel  
7 adjustment proceeding next year for the balance of the  
8 two and a half months of the agreement. But relative  
9 to the fuel factors, there is only a portion of the  
10 revenues that apply to the credits. In this, the year  
11 2000 factors, it's \$36 million out of the \$44 million.

12       **Q**     Okay. So \$36 million. Can you tell me  
13 then, as I understand it, what you're recommending  
14 then is that the O&M costs and the carrying cost is a  
15 plant cost associated with this would then be  
16 unseparated for the year 2000 as a result of your  
17 flowing through the file adjustment clause all of this  
18 revenue; is that correct?

19       **A**     That's correct and the environmental clause.

20       **Q**     And the environmental, correct. For the  
21 year 2000, can you tell me how much would be  
22 associated with the O&M costs that would otherwise be  
23 separated if the Commission determines that it wants  
24 to continue with the separation factor that it imposed  
25 in applying the last stipulation?



1           A     If you give me a moment I believe I do have  
2     that.

3           Q     Thank you.

4           A     I apologize. I have this in different  
5     dollar bases. It's in 1999 dollars. But I do have  
6     the answer.

7           Q     I don't understand what you mean. You have  
8     it in 1999 dollars.

9           A     I have it in current year dollars versus  
10    year 2000 dollars. It's the time value of the  
11    dollars.

12          Q     Okay. So you're simply looking for, it's  
13    just discounted back one year?

14          A     That's correct.

15          Q     Is the \$36 million discounted back one year?

16          A     No, it is not.

17          Q     Okay. Would you give me the O&M expenses?

18          A     Well, I do -- I'm sorry. I do have it in a  
19    rate bill. I'll give you the total dollars. The O&M  
20    dollars are \$3,390,150. And that corresponds to a  
21    rate of \$2.10 per megawatt hour in the year 2000.

22          Q     Okay. Can you tell me what the average fuel  
23    costs that are anticipated as necessary to serve this  
24    contract for the year 2000?

25          A     Yes, I can. I need to clarify that the

1 number that I just read you is for the full 14 and a  
2 half months. It's not for the calendar year. I  
3 apologize.

4 Q Okay. Do you have that number for a  
5 calendar year?

6 A Not directly in front of me.

7 Q Okay.

8 A The weighted -- let's see. You just asked  
9 me about the fuel cost?

10 Q Yes.

11 A The fuel cost, and I will give this again in  
12 the 14 and a half months. That's how I've got the  
13 information in front of me. The projected system  
14 average fuel and purchased power costs -- and this is  
15 right off the Line 20 in Ms. Zwolak's testimony if you  
16 were to use the number. This is not the incremental  
17 fuel cost but it's what we used in my late-filed  
18 exhibit.

19 Using the system average fuel and purchased  
20 power cost rates of \$20.87 per megawatt hour, so that  
21 includes average fuel plus all of the purchased power  
22 that's in our projected fuel filing, you come up with  
23 a number for the 14 and a half months of \$33,557,257.  
24 The actual incremental fuel cost associated with the  
25 sale, just for comparison, is \$27,942,048.

1 Q Okay.

2 A I'm sorry. The rate for that is \$17.38.

3 And that number, just to help clarify, is the assigned  
4 units, the Big Bend 2 and 3, and Gannon 5 and 6  
5 weighted average incremental fuel costs associated  
6 with making the sale.

7 Q And Mr. Hernandez, as I recall there was an  
8 exhibit attached, I believe, to your deposition  
9 wherein some of these costs were displayed and there  
10 was an entry for SO2; is that correct?

11 A That's correct.

12 Q Can you tell me what that is please?

13 A Okay. Again in 1999 dollars, the amount for  
14 the SO2 allowance -- and this is a replacement value  
15 of the SO2, which is much higher than the actual SO2  
16 costs incurred by internalized costs -- the value is  
17 \$2,558,140.

18 Q All right. And I think, unless I'm missing  
19 a component, the final piece of the effect would be  
20 the carrying costs associated with the capital assets  
21 involved in providing this sale. Do you have that?

22 A If you give me a moment, I believe I do.

23 The carrying costs associated with the existing  
24 separation methodology would be calculated by using  
25 the current rate of \$18.50 per kW month times 150

1 megawatts. That's the amount of the sale for the year  
2 2000, times 12 months, and that value is  
3 \$33.3 million.

4 Q Okay. Now -- and that's what you're telling  
5 me the return costs, the overall rate of return plus  
6 the depreciation associated with that portion of plant  
7 or is -- tell me where the depreciation expense  
8 associated with that portion of plant would be. Would  
9 that be in the O&M expenses you gave earlier or is  
10 that included in this number that you've just given?

11 A I believe it's included in the 18.50 but I'd  
12 have to check.

13 Q Okay. Now, then do I have it correct then  
14 that what you're saying -- and again, part of the  
15 problem is, I think we have jumped a little bit from  
16 12 months to 14 and a half months, but correct me if  
17 I'm wrong. And we have also mixed a little bit  
18 between the year 2000 and the year 1999 as far as  
19 dollars. But conceptually what I understand you're  
20 suggesting is that you would flow back \$44 million,  
21 the entire amount of the revenue in fuel adjustment  
22 for the FMPA sale to the benefit of the retail  
23 customers, and in the base rate effect would be  
24 \$33 million -- I'm sorry. The base rate effect would  
25 be \$33 million additional carrying costs associated

1 from the nonseparation, the \$2.5 million of O&M  
2 expense and the \$3.39 million of the SO2. Is that  
3 correct or have I mischaracterized something?

4       **A**     I'm -- just to qualify or to better  
5 understand it, \$33.3 million that we calculated is  
6 based on separation, not nonseparation.

7       **Q**     That's what I'm speaking of. But what  
8 you're asking basically in this proposition is that  
9 where the Commission separated this out before, what  
10 you are suggesting is that it not be separated?

11       **A**     That's correct. But the impact on the cost  
12 recovery clauses, the \$33.3 million, is simply a loss  
13 to the company; that those resources were part of the  
14 reserves that were in place at the time that we made  
15 the deal back in 1996. So to the extent that those  
16 resources were there, the sale was based on an  
17 incremental type consideration.

18               From the company's perspective there wasn't  
19 a consideration that this was a good deal for  
20 ratepayers and customers and company, the ratepayers  
21 alike to the extent that we had to separate the sale.  
22 And the \$33.3 million, therefore, if that was -- if we  
23 continued the separation, becomes a huge expense to  
24 the company with no benefit to the ratepayers because  
25 then the company retains 100% of those revenues. And

1 the \$44 million, again, is spread over the 14 and a  
2 half months. It's \$36 million approximately in the  
3 year 2000 and approximately \$8 million in the first  
4 quarter.

5 So when you annualize that you don't get the  
6 same rate reduction and that was the way that it was  
7 described in my Late-filed Exhibit No. 2 attached to  
8 my deposition.

9 Q I'm trying to figure out -- I'm trying to  
10 get from you the dollar impact of the change in the  
11 separation that would be associated with what you're  
12 seeking that would be effected by the change in plant  
13 separation.

14 A Impact to the customer?

15 Q The impact on your base rates. The impact  
16 on your base rates earnings?

17 A That's the \$33.3 million.

18 Q Okay. That's the \$33.3?

19 A Right.

20 Q And that's just from the plant side? That's  
21 not the O&M side?

22 A That's correct.

23 Q Okay. So you would have the \$33 million,  
24 the \$3.39 million and the \$2.5 million would be the  
25 impact reduction on your base rate earnings as a

1 result of that; is that correct?

2 A I believe that's correct.

3 Q Okay. And then I think you said the average  
4 fuel cost that would be associated with serving this  
5 contract would be \$33.5 million; is that correct?

6 A No. The weighted average incremental fuel  
7 cost associated with serving the sale is that other  
8 number. I had simply gave you the system average  
9 because I believe that's what you asked me.

10 Q You said the incremental was \$27.9 million  
11 and the weighted average cost for that amount of fuel  
12 for the same period was \$33.5 million?

13 A No. Those are two different numbers. The  
14 weighted average, \$27.9 million, is taking the  
15 incremental fuel cost from the four identified sources  
16 that will be serving the sale; that's Gannon 5 and 6,  
17 Big Bend 2 and 3. So that's the true incremental fuel  
18 cost associated with serving the sale; the fuel cost  
19 component.

20 When you ask the question related to what  
21 would the system number be, in our late filed -- in my  
22 Late-filed Exhibit No. 2, we showed that even if you  
23 looked at the total system average not just those four  
24 units fuel average, which would be maybe something  
25 closer to \$19 versus the \$17.38 weighted average -- if

1 you even stepped it up and included that all the units  
2 on our system average fuel cost, plus all of the  
3 purchases that are in our projected, that's where you  
4 come up with the rate of \$20.87 per megawatt hour.  
5 That's what drives the \$33.5 million number.

6 Q And that's for the same period?

7 A It's for the same period, right. And simply  
8 we did it that way to demonstrate that even if you  
9 included the total system, fuel and purchased power  
10 cost, you still get net benefits to the ratepayers.  
11 We're somewhere -- in an actual basis somewhere in  
12 between.

13 Q Now, that's assuming nothing is captured in  
14 base rates; is that correct?

15 A Captured by base rates in terms of?

16 Q In terms of some type of earnings limitation  
17 imposed by the Commission on base rates for the year  
18 2000?

19 A That's correct.

20 Q Mr. Hernandez, you do have rebuttal  
21 testimony and I have some specifics on the 80/20 split  
22 with regard to that, but before we get into that I  
23 just have a general question or some general questions  
24 on it.

25 I understand your point for the need for an



1 incentive. I guess my question is, isn't this  
2 incentive all one way? That is, there is no downside  
3 to it?

4 A We're referring to economy sales or making  
5 cost systems --

6 Q Yes. The 80/20 split on economy sales.

7 A I don't understand when you say there is no  
8 downside.

9 Q Well, let me start from this proposition.  
10 You agree that because you've been given a proper  
11 return, a reasonable return on your investment --  
12 because Tampa Electric's been given a reasonable  
13 return on its investment, a reasonable effort to keep  
14 prices as low as possible is expected in exchange; is  
15 that correct?

16 A I would agree with that.

17 Q And what you're suggesting, though, is that  
18 some specific incentive is helpful for the purpose of  
19 assuring as much aggressiveness as prudent for each  
20 company to make as much sales to keep the prices as  
21 low as possible; is that correct?

22 A To an extent. And this gets back to the  
23 supply. I can't say yes or no without talking a  
24 little bit. This whole issue of reserves and what you  
25 compile in terms of available supply side resources,

1 if we were simply to say, we're going to carry a 30%  
2 reserve margin, certainly we're going to mitigate any  
3 of the reliability issues that we have for either firm  
4 or the nonfirm customers, but it comes at a price. It  
5 comes at a price in terms that we would probably seek  
6 rate base relief because we simply can't carry 30%  
7 reserves without some impact on price.

8 But, if you were in that situation and you  
9 had now available resources to get on the market, you  
10 know, arguably is the 80% or even 100% of that margin  
11 enough to offset what the customers would realize in  
12 terms of the base rate effect. So there's a fine  
13 balance there in terms of maintaining the adequate  
14 reliability criteria; what is the appropriate  
15 criteria; what are the resources that you need to have  
16 and at what price; what is the cost and, therefore,  
17 what is the price. So these type of transactions,  
18 these nonfirm transactions, are clearly driven by what  
19 resources you put in place, the availability of those  
20 resources, either your existing system or the  
21 purchased power arrangements that you have and your  
22 ability to work the market.

23 I agree with some of the comments that  
24 Mr. Howell earlier, with most of them, in fact. There  
25 are some differences between our two companies, Tampa

1 Electric and Gulf, in terms of how we enter into the  
2 market and what we characterize as economy  
3 transactions perhaps. But, effectively, by having an  
4 incentive there actually is a reliability benefit but  
5 you've got to balance the cost and the price issue  
6 between not only our ratepayers but also the other  
7 ratepayers, the wholesale market players that are, in  
8 turn, buying power or selling power to met someone  
9 else's firm commitments, and then, of course, our  
10 shareholders.

11 I mean, if we were to price ourselves out of  
12 the market effectively by carrying a 20% or 30% supply  
13 side margin, that's not the right thing to do for our  
14 ratepayers and wouldn't be the right thing for our  
15 shareholders because we tend to -- that would expose  
16 ourself to the extent that the wholesale market  
17 continues to change in this state. And it is a  
18 dynamic and robust market right now. But, it's  
19 difficult to say that, you know, what that amount of  
20 resources should be, and should there be an incentive.  
21 I think having a carrot versus a stick or disincentive  
22 makes a big difference.

23 So to the extent those remarks by  
24 Mr. Howell, I totally agree with and fully support  
25 that the Commission should retain an incentive, and

1 not just for the economy transactions. We should  
2 consider it for all types of transactions.

3 Q I don't think you understood the question.

4 A I will try again then.

5 Q The point that I'm making is -- and I will  
6 simply offer this and you tell me. Is it not correct  
7 that given that you're receiving a reasonable return  
8 before you make any economy sales that you -- a  
9 company could make less than optimum effort at making  
10 economy sales; less than reasonable effort; less than  
11 what the Commission should reasonably expect a  
12 regulated utility to make, and yet get more than a  
13 reasonable return because every sale adds to the  
14 profit of the company?

15 A Well, margin aside --

16 Q Is that correct?

17 A There's a benefit to the company in the  
18 corporation for making these types of transactions.  
19 The effective credits that go back in the lowering of  
20 the retail rates. There is a benefit to that, as was  
21 discussed before.

22 But to the extent that this market is very  
23 dynamic, the fact that we've had to add additional  
24 resources since our last rate case, it's not so much  
25 knowing the market, it's working the market. And that

1 works both on the wholesale side when you're making  
2 sales, but also when you're buying and so -- I mean,  
3 there is no guarantee that you're going to make these  
4 opportunity sales. You've got to expend the  
5 resources. You got to spend the dollars to provide  
6 the information to the folks that make these types of  
7 transactions. And there is, I would say, a difference  
8 in the effort. It's not to say that we wouldn't make  
9 or seek to make cost-effective transactions, either  
10 buying capacity and energy or selling capacity or  
11 energy, but would we have the same level of resources  
12 dedicated to that in the absence of an incentive, I'd  
13 say there would be a difference.

14 Q Well, I'm not sure whether you answered the  
15 question. My question -- are you telling me that the  
16 answer might be no because you've got assets and  
17 expenses devoted to it that were encountered  
18 subsequent to your last rate case? I'm trying to  
19 understand how it can be anything other than yes for  
20 every sale that a company makes, even if the effort is  
21 below that that's reasonable or reasonably expected,  
22 yes, you get higher than a reasonable return because  
23 you are already receiving a reasonable return to the  
24 establishment of your base rates?

25 A But doesn't that depend on where we are at

1 in terms of the range? I mean, if we're below our  
2 ceiling and we still have that opportunity to go up,  
3 for Tampa Electric to 12.7 -- 12.75% on return, then  
4 we have the ability to or shouldn't we be allowed the  
5 ability to be aggressive or as aggressive as we can in  
6 these sales and enjoy some type of return for that  
7 effort?

8 Q You're asking me a question?

9 A I think I did.

10 MR. BURGESS: Should I be under oath,  
11 Commissioner?

12 COMMISSIONER DEASON: Let me ask this  
13 question and this is a question. How is the 20% that  
14 is retained by shareholders for economy sales under  
15 the broker, how is that accounted for? Is that above  
16 or below the line for regulatory purposes?

17 WITNESS HERNANDEZ: Below the line.

18 COMMISSIONER DEASON: So then how would it  
19 impact your earnings for your determination of your  
20 range if it booked below the line?

21 WITNESS HERNANDEZ: It doesn't. I spoke  
22 incorrectly.

23 Q (By Mr. Burgess) When you say that you  
24 have expenses associated with examining these -- and I  
25 agree that a great deal more effort has been put into



1 trying to establish the optimum amount of these sales  
2 to be made and discovering where the markets are. But  
3 what is the accounting for these expenses for these  
4 particular departments that you're speaking of that do  
5 this examination? What account does it go into?

6 A I don't know what the specific FERC account  
7 is. I'm sorry.

8 Q Do you know whether it's an account that  
9 would be an above the line expense for the purpose of  
10 establishment of base rates?

11 A I believe it is an above the line expense.

12 Q And so for any surveillance purposes, any  
13 stipulation that involves earnings, they would be  
14 accounted for and paid for through base rates; is that  
15 correct?

16 A I believe that's correct.

17 Q Okay. Thank you, Mr. Hernandez.

18 COMMISSIONER DEASON: Staff, how much do you  
19 have for this witness?

20 MR. KEATING: I'd estimate about 20 minutes.

21 COMMISSIONER DEASON: Okay. We're going to  
22 take a recess. We will reconvene at 20 minutes after  
23 11:00.

24 MR. KEATING: Okay.

25 (Brief recess.)

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**COMMISSIONER DEASON:** Call the hearing back to order. Staff, you may inquire.

**CROSS EXAMINATION**

**BY MR. KEATING:**

**Q** Mr. Hernandez, how does TECO treat transmission revenues received from nonseparated nonfirm wholesale energy sales not made through the broker?

**A** Transmission revenues, you said?

**Q** Yes.

**A** They're credited back. These are noneconomy sales?

**Q** Excuse me?

**A** These are noneconomy, nonseparated sales?

**Q** These are the economy sales, nonbroker.

**A** Economy sales nonbroker, the company retains 20% of those revenues and flows 80% back through the fuel clause.

**Q** You flow back 20% of the transmission revenues from those sales? My question related only of the transmission revenues.

**A** On economy transactions a broker or off broker the company retains 20% of those revenues. Off broker or on broker noneconomy transactions, 100% of



1 those revenues are flowed back through the fuel  
2 clause.

3 Q In a rate case, is it correct that  
4 transmission costs are allocated to the various rate  
5 classes on a demand basis?

6 A I believe that's true.

7 Q How does TECO record generation related  
8 gains on nonseparated nonfirm wholesale sales that are  
9 not made through the broker?

10 A On economy transactions that fall under that  
11 category the company retains 20%. And economy, again,  
12 for Tampa Electric is Schedule C and Schedule X  
13 transactions only. Other nonfirm nonseparated  
14 transactions that are off the broker, 100% of those  
15 gains are credited back on the generation side through  
16 the fuel clause.

17 COMMISSIONER CLARK: Do I understand there  
18 is a bit of inconsistency among the companies as to  
19 how that is treated?

20 WITNESS HERNANDEZ: I think it's more of a  
21 definition of what we each characterize as economy,  
22 Commissioner Clark.

23 COMMISSIONER CLARK: Well, you say C and X  
24 are economy.

25 WITNESS HERNANDEZ: Yes. For Tampa Electric

1 that's true.

2 COMMISSIONER CLARK: And you split 20/80 for  
3 those sales?

4 WITNESS HERNANDEZ: Yes, we do.

5 COMMISSIONER CLARK: And it's J and O  
6 something?

7 WITNESS HERNANDEZ: We don't -- well, all  
8 other nonfirm or these as available transactions,  
9 either on the broker or off the broker are credited  
10 back 100% of the gain, both on the transmission as  
11 well as the generation gain, credited back to the fuel  
12 clause.

13 COMMISSIONER CLARK: You have to talk to me  
14 in terms of schedules.

15 WITNESS HERNANDEZ: Okay. All other  
16 schedules except for C and X, 100% of the gains  
17 generation and transmission revenues are credited back  
18 through the fuel clause.

19 COMMISSIONER CLARK: Does FP&L have the same  
20 C and X schedules?

21 WITNESS HERNANDEZ: I'm not the best person  
22 to ask, but I believe their Schedule Cs and Xs are  
23 comparable to ours in terms of the concept, but I'm  
24 not sure.

25 COMMISSIONER CLARK: Well, then let's forget

1 the schedules. Do you think all economy sales are  
2 being treated the same? If they have the same  
3 characteristics, are they being treated the same with  
4 respect to the 20/80 split?

5 **WITNESS HERNANDEZ:** For Tampa Electric, yes,  
6 ma'am.

7 **COMMISSIONER CLARK:** For all companies, do  
8 you know?

9 **WITNESS HERNANDEZ:** I don't know. I don't  
10 know.

11 **COMMISSIONER CLARK:** Does it make sense to  
12 treat them all the same?

13 **WITNESS HERNANDEZ:** It may.

14 **COMMISSIONER CLARK:** Why would you not treat  
15 them the same?

16 **WITNESS HERNANDEZ:** I really don't know what  
17 the circumstances would be for the other companies in  
18 terms of how they make those transactions, so, again,  
19 I can only speak for Tampa Electric.

20 **COMMISSIONER CLARK:** Can you think of any  
21 circumstances why it wouldn't be appropriate?

22 **WITNESS HERNANDEZ:** No. I believe  
23 transactions -- C and X type transactions that are  
24 made on the broker as well as off the broker should be  
25 treated the same, and so, therefore, a 20% incentive

1 should be retained by the investor-owned utilities  
2 that make those transactions.

3 COMMISSIONER CLARK: What is a J  
4 transaction?

5 WITNESS HERNANDEZ: A Schedule J transaction  
6 is typically a transaction that's one year or less.  
7 That could be firm or nonfirm. It's a negotiated  
8 contract that's different than the split the savings  
9 concept, that's attributed to what we characterize as  
10 economy transactions. It's simply a negotiated  
11 reservation or capacity charge; a negotiated energy  
12 charge that includes fuel and O&M and it's a willing  
13 seller and a willing buyer, generally off broker, I  
14 believe.

15 COMMISSIONER CLARK: How is it different  
16 from a C or X transaction?

17 WITNESS HERNANDEZ: Well, it's still cost  
18 based type transaction. By negotiating what the  
19 transaction price would be we can effectively get a  
20 greater margin relative to the incremental cost to  
21 make the Schedule J sale and then flow 100% back to  
22 the ratepayer. I'm not answering your question, am I?

23 COMMISSIONER CLARK: The difference is that  
24 one is -- Mr. McWhirter, I think you need to quit  
25 fiddling with that.

1                   **MR. MCWHIRTER:** I will step out.

2                   **COMMISSIONER CLARK:** The difference is that  
3 one is based on incremental and decremental costs and  
4 the other is based on what you negotiate?

5                   **WITNESS HERNANDEZ:** That's correct.

6                   **COMMISSIONER CLARK:** Are you arguing that  
7 the one you negotiate should be treated the same with  
8 respect to the 20/80 split and, in effect, that those  
9 should be subject to the shareholders getting 20%?

10                  **WITNESS HERNANDEZ:** I think the Commission  
11 should consider that. To the extent that because it's  
12 a negotiated transaction, it's not as simple as just  
13 identifying what your avoided costs are if you're a  
14 buyer, or identifying what your incremental costs are  
15 if you're a seller.

16                  In either case, in any type of transaction,  
17 you should know what those are. But a negotiated  
18 transaction is such that you've got to the utilize,  
19 again, the knowledge of the market. You've got to  
20 work the market to raise the transaction price and to  
21 use those same numbers as before, that Mr. Wieland  
22 talked about and Mr. Howell talked about; the \$20  
23 seller cost; the \$30 buyer. In the economy  
24 transaction, you simply take the two, add them  
25 together and divide by two. So the transaction price



1 there would be \$25 per megawatt hour.

2 In a negotiated J transaction, if my  
3 incremental cost is still \$20 but I can negotiated a  
4 \$27 transaction price versus what I would have gotten  
5 on the broker at split the savings or off the broker  
6 split the savings, I just raised the bar in terms of  
7 the margin for our company and or our ratepayers. And  
8 the way that we're handling this right now, that full  
9 margin and this example, the \$7 per megawatt hour,  
10 would be credited back 100%.

11 **COMMISSIONER CLARK:** If that's the case why  
12 do you as a company ever negotiate a J contract?  
13 You're not going to get any.

14 **WITNESS HERNANDEZ:** That's a good question.  
15 Part of it has to do with the benefits that the  
16 ratepayers receive. But arguably, if have you to work  
17 harder for those negotiated contracts, this Commission  
18 should consider an incentive back to the company for  
19 its shareholders to enter into those type of  
20 transactions because it's not simply matching the high  
21 to low. You've got to work the market.

22 **COMMISSIONER CLARK:** Can you tell me how  
23 much you have subject to a J contract and how much you  
24 have subject to a C and X contract?

25 **WITNESS HERNANDEZ:** Energy? I don't know.

1 Again --

2 COMMISSIONER CLARK: You threw in energy.

3 Why is that important?

4 WITNESS HERNANDEZ: Because C and X, it's  
5 typically not a capacity.

6 COMMISSIONER CLARK: Okay. J has the  
7 capacity.

8 WITNESS HERNANDEZ: More energy driven. The  
9 J is more of a capacity type contract with some energy  
10 tied to it and I don't have a feel for what our  
11 current obligations or what our current market  
12 opportunities are.

13 COMMISSIONER CLARK: Thank you.

14 Q (By Mr. Keating) Mr. Hernandez, I've got  
15 an exhibit I'd like you to take a look at. I just  
16 have a few questions on that.

17 MR. KEATING: It's a composite exhibit.  
18 Consists of TECO's response to Staff's First Set of  
19 Interrogatories No. 10, TECO's Late-filed Deposition  
20 Exhibit No. 2 to Mr. Hernandez's deposition and the  
21 Late-filed Exhibit No. 5 to Mr. Hernandez's  
22 deposition. Staff would ask that that be marked for  
23 identification.

24 COMMISSIONER DEASON: Exhibit 31.

25 (Exhibit No. 31 marked for identification.)

1           Q        **(By Mr. Keating)** Mr. Hernandez, turning to  
2 the first page of that exhibit. I realize that this  
3 is not a response that you sponsored, but are you  
4 familiar with these figures or --

5           A        Yes, I am.

6           Q        Do you know what percentage of these economy  
7 sales are broker sales versus off broker sales?

8           A        It changes from year to year. Between 1990  
9 and 1998 the numbers range from 62% on broker up to  
10 95% on broker, and the difference, the balance of the  
11 percentage being off-broker type transactions.

12          Q        For 1998, do you know what that percentage  
13 was?

14          A        62% were made on broker.

15          Q        And for the purchases, do you -- can you  
16 break those down into percentage of on broker and off  
17 broker economy transactions?

18          A        Every year? I'm sorry.

19          Q        For 1998.

20          A        For 1998, 62% of the 744,079 megawatt hours  
21 were on broker, and then 38% of that number would  
22 be --

23          Q        I going on to the next column. I'm sorry I  
24 didn't make that clear. The next column entitled  
25 Economy Megawatt Hour Purchases.



1           A     Okay. I'm sorry.

2           Q     Can you break those down into off broker and  
3 on broker transactions?

4           A     It ranges, again, between that period,  
5 roughly 75% up to 97%.

6           Q     On broker?

7           A     Made on broker.

8           Q     And for 1998 do you know what the breakdown  
9 is?

10          A     97% on broker.

11          Q     Okay. I believe you stated before that  
12 Tampa Electric applies a 20% incentive factor only on  
13 economy sales made under Schedules C and X; is that  
14 correct?

15          A     That's correct. Made either on broker or  
16 off broker.

17          Q     Okay. Why doesn't TECO apply the incentive  
18 to market based economy energy sales?

19          A     Market based priced economy?

20          Q     Yes.

21          A     I guess by definition we -- a market based  
22 priced transaction doesn't fit our definition of what  
23 our incremental cost is. In that sense a market based  
24 priced transaction would -- I guess I would envision  
25 this as being an off broker type transaction, and at

1 this point we've made some of those sales, but we  
2 flowed 100% of those margins back because my  
3 understanding is we don't have the ability as yet to  
4 retain 20% of those margins.

5 Q Okay. So does TECO believe that the  
6 Commission's 1985 order approving the 20% incentive  
7 does not apply to market based priced economy sales or  
8 market based priced sales? As I understand it, you're  
9 saying that market based priced transactions are not,  
10 under your definition of an economy transaction, an  
11 economy transaction?

12 A Yes. And the reason why -- I will clarify  
13 the last point. The reason why I say in my opinion  
14 that that would not be an economy type transaction,  
15 because by definition, we would be selling at a cost  
16 higher than our incremental cost. And an economy type  
17 transaction, we would simply be putting out there our  
18 incremental costs of fuel in the associated O&M and  
19 SO2 allowance cost, and that's what gets used to  
20 determine the transactions price with the buyer,  
21 again, under decremental or avoided costs.

22 In a market based priced transaction, you're  
23 hopefully something much greater than your incremental  
24 cost. Now, if this Commission determined that by the  
25 order that came out in the 1985 proceeding that we

1 should be allowed a 20% margin, we would certainly  
2 agree to that.

3 Q Do you think that that order did apply to  
4 market based priced transactions?

5 A We haven't interpreted that at this point.

6 Q When Tampa Electric participates in an  
7 economy energy transaction, is it exceeding its  
8 obligation to provide cost-effective electric service  
9 to its retail ratepayers?

10 A Is Tampa Electric exceeding our obligation?

11 Q Yes.

12 A I'm sorry. Could you rephrase it -- or  
13 repeat the question?

14 Q Yes. When Tampa Electric participates in an  
15 economy energy transaction, is TECO exceeding its  
16 obligation to provide cost-effective service to its  
17 retail ratepayers?

18 A I would say that if it were exceeding --  
19 again, as we discussed earlier, I believe that's -- to  
20 the extent that we've got available resources and  
21 there is a willing buyer, I think we should do so, to  
22 some level.

23 Q What incentives does TECO have to purchase  
24 economy energy?

25 A To reduce the production costs that we would

1 otherwise incur by utilizing our own resources. To  
2 the extent that there is lower cost available  
3 resources the customers benefit by providing that  
4 incremental energy with the lower cost incremental  
5 resource.

6 Q Do TECO's shareholders receive any direct  
7 financial incentive for making economy purchases?

8 A Not at this time, no.

9 Q Okay. Do they intend to apply an incentive?

10 A If the Commission is willing to consider  
11 that, we would certainly entertain those thoughts.  
12 That's not our intent in our filing.

13 Q Does Tampa Electric recover the capital and  
14 fixed O&M costs of its generating resources through  
15 its base rates?

16 A I'm sorry. I couldn't hear the first part  
17 of the question.

18 Q Does Tampa Electric recover the capital and  
19 fixed O&M costs of its generating resources through  
20 its base rates?

21 A Yes, it does.

22 Q Are these the same generation resources from  
23 which TECO would make an economy energy sale?

24 A Yes, they are.

25 Q Okay. Can Tampa Electric sell economy

1 energy at market based rates?

2       **A**     I believe, as I was saying earlier, my  
3 definition of selling economy wouldn't fit, a market  
4 based priced transaction wouldn't fit. Tampa Electric  
5 does have the ability to engage in market price based  
6 transactions within and without -- outside the state.  
7 I'm sorry.

8       **Q**     What percentage of these transactions are  
9 made in state versus out of state?

10       **A**     I'm not sure.

11               **COMMISSIONER CLARK:** Mr. Hernandez, to your  
12 knowledge, does FP&L make Schedule J sales in Florida?

13               **WITNESS HERNANDEZ:** I'm not sure if they  
14 have Schedule J transactions. I don't know.

15               **COMMISSIONER CLARK:** If they did have a  
16 Schedule J, would it be the same as yours?

17               **WITNESS HERNANDEZ:** I'm not sure.

18               **COMMISSIONER CLARK:** I thought in your  
19 testimony you indicated that they did have Schedule J  
20 and that was just -- maybe it was your rebuttal --  
21 some confusion as to what the comparison --

22               **WITNESS HERNANDEZ:** I believe in my --  
23 either my rebuttal testimony I was really focusing on  
24 Tampa Electric as what we consider to be economy  
25 transactions, the C and X. I might have referred to

1 Schedule J, but it would be specific to Tampa  
2 Electric.

3 Q (By Mr. Keating) Mr. Hernandez, for the  
4 1999 recovery period how much revenue will TECO  
5 receive from out of state economy sales?

6 A Again, I'm not sure how much of the economy  
7 sales that we're making out of state. I don't know.

8 Q Do you know how much -- what level of  
9 purchases -- economy purchases TECO would make from  
10 out of state?

11 A I believe most of the purchases are from  
12 within the state, but again, I'm not sure on the exact  
13 proportion.

14 Q How does TECO treat the revenues from out of  
15 state economy sales?

16 A They would be treated just the same as if  
17 there was an in state transaction, either on broker or  
18 off broker. We would retain 20% of the margin.

19 Q How would the remainder of the gain that's  
20 credited to the ratepayers be credited?

21 A The gain would be the same. 80% of that  
22 gain would be credited back to the fuel cost recovery  
23 clause.

24 Q I'm going to go on to some questions about  
25 the FMPA sale. Could you describe the current

1 regulatory treatment as ordered by the Commission in  
2 1997 for your contract with FMPPA?

3 A The Commission ordered Tampa Electric to  
4 separate the FMPPA sale during the stipulation period.

5 Q Is there a capacity charge associated with  
6 the sale of wholesale energy and capacity to FMPPA?

7 A Yes, there is.

8 Q Is there a transmission charge associated  
9 with that sale?

10 A Yes, there is.

11 Q On Page 10 of your prefiled testimony you  
12 refer to the FMPPA wholesale sale as an incremental or  
13 opportunity sale; is that correct?

14 A Yes. On Line 10 of my testimony, that's  
15 correct. Page 10.

16 Q Can you explain what you mean by an  
17 incremental or opportunity sale in this context?

18 A Sure. What I mean by that is that an  
19 incremental sale or an opportunity sale is one, in my  
20 opinion, does not change the resource expansion plan.  
21 It does not require additional resources. It's simply  
22 using the available reserves, if you will, or supply  
23 side resources in excess of the company's prescribed  
24 reliability criteria.

25 So, for example, for Tampa Electric at the

1 time that this transaction was entered into in 1996,  
2 Tampa Electric had reserves projected approximately  
3 20%. And so, our criteria at that time was 15% and so  
4 we effectively had 5% reserve margin that would be  
5 there in excess of our minimum to make opportunity  
6 sales.

7 Opportunity sales can be configured in  
8 either a nonfirm or firm. To the extent that you  
9 enter into a firm transaction, as long as you're above  
10 your minimum planning criteria, the company should be  
11 encouraged to make these type of transactions. This  
12 transaction was priced on an incremental cost basis,  
13 again, with the thought that to the extent the  
14 resources above our minimum were available that we  
15 would charge an appropriate amount to recover both the  
16 fuel and variable operating costs and some gain.

17 And that initially our concept was to share  
18 the gain 40% to the shareholders and 60% to the  
19 ratepayers with no separation. And in subsequent  
20 proceeding, the Commission determined that we needed  
21 to separate and that therein lied the economics and  
22 why that type of treatment didn't work for us during  
23 the stipulation period.

24 Q Could you refer to Exhibit TLH-1 attached to  
25 your prefiled testimony.



1           A     Should we refer to the amended or revised  
2 document?

3           Q     Yes. Could you tell me what information is  
4 shown on this exhibit?

5           A     In the revised document we're showing, as of  
6 October of this year, what the cumulative benefits  
7 associated with this transaction going back to the  
8 retail ratepayers. For the first section of data, we  
9 cover the period of 1997 through 1999. And for 1999  
10 it's an actual slash estimate; an estimate, if you  
11 will, for the balance of 1999 at the time that we  
12 prepared these numbers.

13                     What that reflects, in 1997 dollars the net  
14 benefits back to the retail ratepayers were  
15 \$9.8 million approximately in 1997 dollars. That  
16 compares to what Tampa Electric talked about in the  
17 1997 proceeding of approximately \$9 million in  
18 benefits. And that's why we put this in 1997 dollars  
19 so we could compare on a common dollar basis.

20                     The point of doing that was to demonstrate  
21 that while we had estimated \$9 million for the whole  
22 transaction -- from 1997 through March 15th of year  
23 2001, while we estimated \$9 million benefits, we've  
24 already accrued \$9.8 million benefits.

25                     The next line goes to the balance of the

1 transaction, the last 14 and a half months, from  
2 January, 2000, to March 15, 2001. The corrected  
3 number there is \$3.4 million net benefit to the  
4 ratepayers and that's even using the more prescriptive  
5 number of -- using system average fuel and purchased  
6 power as the rate to -- if we were to credit back  
7 against those total revenues versus what the real cost  
8 is and that's the incremental fuel cost associated  
9 with those units -- fuel and SO2 allowance, I'm sorry,  
10 associated with the Gannon 5 and 6 and the Big Bend 2  
11 and 3 units.

12 So we used a number that generated a very  
13 conservative reforecast of the balance of the  
14 transaction benefits. The next column simply takes  
15 those -- estimates a total net benefit by combining  
16 the \$9.8 million with \$3.4 million and you get to the  
17 \$13.2 million net benefit for the entire transaction.  
18 And, again, on -- the next line shows the original net  
19 benefit estimate for the whole period of \$9 million.

20 Q Thank you. Can the net benefit to retail  
21 ratepayers for the 2000 to 2001 period be described as  
22 the difference between the revenues received from FMPA  
23 and the incremental cost of SO2 emission allowances  
24 and fuel to provide the 150 megawatts of capacity and  
25 energy to FMPA?

1           **A**     It would. What we showed here was not the  
2 incremental unit fuel cost. The benefits would be  
3 much greater. This is, again, the system average but  
4 that's how it -- conceptually, that's how it would  
5 work.

6           **Q**     Is it possible that the incremental cost of  
7 fuel and SO2 allowances will exceed the revenues  
8 received by TECO under this contract?

9           **A**     I do have that figure for you, if you like.  
10 The incremental fuel cost -- and I believe I spoke of  
11 this earlier -- using the weighted average fuel cost  
12 from those assigned units would be \$27.9 million. And  
13 the associated SO2 expense, the \$2.56 million, is  
14 based off of those four units serving the sale. It's  
15 also using a much higher figure for the SO2 allowance  
16 as a credit. We're utilizing -- and it's in footnote  
17 No. 3 -- a market replacement value of those SO2  
18 allowance costs of \$225 per ton.

19                   The internalized cost -- what I mean by  
20 internalized cost is the actual cost associated with  
21 fuel blending or scrubbing -- is much less than that.  
22 So we again used a much more conservative number by  
23 using a higher replacement value. So we've got  
24 conservatism built into these numbers that reflects a  
25 higher replacement value of the SO2 allowance cost and

1 includes the total system average fuel in excess of  
2 the incremental unit fuel associated with serving the  
3 sale. And we're utilizing the total purchases that  
4 are in our projection. So, it's pretty safe to say  
5 that this is a very conservative approach that still  
6 yields benefits.

7 Q Does that amount include O&M costs?

8 A It's got -- yes, it's got O&M using, again,  
9 the variable O&M rate prescribed by the Commission by  
10 the methodology that came up with, and this is in  
11 Footnote No. 2, \$2.10 per megawatt hour in the year  
12 2000, and \$2.15 in 2001. It's the same value that we  
13 would use for economy type transactions.

14 Q So is it possible that these costs will  
15 exceed the revenues received by TECO under the  
16 contract?

17 A Only to the extent that our fuel --  
18 incremental unit fuel cost would be higher than what  
19 we think they're going to be. To the extent -- and  
20 again, this gets back to the contract. By utilizing  
21 the four units that I described before, Gannon 5 and 6  
22 and Big Bend 2 and 3, if those four units or all four  
23 units are unavailable, we are not committed to make  
24 the sale. So we would not be forced to utilize a  
25 higher re -- higher cost resource, for example, a

1 combustion turbine to serve the sale.

2 Q You wouldn't be required to, but could you?

3 A No. We would not be required to. If those  
4 four units are all off line for either planned  
5 maintenance or forced outage, that sale stops. So we  
6 would not be forced to utilize other higher cost  
7 resources to make the sale.

8 Q You mentioned that the incremental fuel cost  
9 may be higher than estimated and that would perhaps be  
10 the only possibility that costs would exceed the  
11 revenues received by TECO under the contract?

12 A The other piece would be purchased power  
13 costs but most of those are contracted. The other as  
14 available purchases would be of economy type or to the  
15 extent that if we had additional forced outages,  
16 unplanned outages in our system, that we don't have  
17 any control over.

18 Q Is TECO going to monitor the fuel costs to  
19 ensure that they don't exceed -- so that we don't have  
20 a situation where costs exceed the revenues?

21 A Well, at this point in time the fuel  
22 contracts are already in place. The reason why I  
23 hesitate as to why there would be any variances is  
24 that the incremental cost is really a function of two  
25 components. It's the fuel cost, which is pretty much

1 set for next year, but it's also a component of the  
2 incremental heat rate. So to the extent that there  
3 were slight variations in what we think the heat rate  
4 is going to be off those units versus if we got warmer  
5 temperatures or changes in cooling water temperature  
6 that effects those heat rates, the incremental costs  
7 could be higher or lower. It's a projection, but we  
8 think our projections are pretty close.

9 Q Well, let me ask if TECO can give the  
10 assurance that if its incremental cost of fuel and SO2  
11 allowances and O&M exceed the revenues that TECO  
12 receives from FMPA contract, will TECO make the  
13 ratepayers whole by crediting that difference through  
14 the fuel clause from operating revenues?

15 A That isn't in our proposal. And, again,  
16 reflecting on the benefits already accrued, we don't  
17 think it's very likely that there's a need for that  
18 type of guarantee. Again, we took a conservative  
19 approach but I would say that our fuel and incremental  
20 heat rate numbers for those units are probably within  
21 a percentage or two. The purchased power agreements  
22 that are already in place that are part of our  
23 presentation or filing is -- are already in place so  
24 we feel fairly confident that our system fuel and  
25 purchased power proxy more than covers that issue,

1 that variance between what the incremental cost from  
2 the units would be.

3 Q Well, if it's -- I guess if it's not that  
4 likely, if you believe that it's not that likely that  
5 you're estimates are going to be that far off, why  
6 would there be any problem with agreeing to make the  
7 ratepayers whole in the unlikely event that those  
8 costs are higher than the revenues received?

9 A Well, again, I don't know. We could have  
10 problems with our unit availability. Just -- our best  
11 guess right now, our best forecast is based on the  
12 best information that we have right now. It's tough  
13 for me to sit here and say that the world can't turn  
14 upside down next year. But we feel fairly confident  
15 about all the assumptions that went into our projected  
16 rates here. Our proposal considers not only the  
17 \$3.4 million benefit, which again is higher if you  
18 really look at the incremental fuel costs, but also in  
19 consideration of the \$9.8 million. So when you look  
20 at that type of benefit that's already been accrued,  
21 as well as what's estimated, I struggle as to what the  
22 need for a commitment on a make whole is.

23 Q Could you turn to the second page of the  
24 exhibit that I handed out, the Staff exhibit. The  
25 second -- on to the third page. It's the table titled

1 Impact on 1000 Kilowatt Hour Residential Bill, Current  
2 and Proposed Treatment for FMPA Contract.

3 A Yes, I've got it.

4 Q Okay. Could you explain what the numbers in  
5 Columns 1 and 2 -- sorry. Strike that. Could you  
6 explain what the numbers under the second and third  
7 columns in that table show us, and those are the  
8 columns titled Total FMPA Revenues Credited, and the  
9 third column titled Less System Average Fuel and  
10 Purchased Power?

11 A Yes, I will. The middle column titled Total  
12 FMPA Revenues Credited is simply taking the  
13 approximately \$36 million in the year 2000 and  
14 splitting it between the environmental and the fuel  
15 cost recovery clauses. So that's a total revenue,  
16 100% revenue credit and -- which is already included  
17 in our projected cost recovery factors.

18 Relative to what's titled the current FMPA  
19 treatment to the extent that that we did not flow 100%  
20 of the revenues and we were to credit -- to pull out,  
21 I'm sorry, the revenues, effectively the difference  
22 would be, on a revenue perspective, \$2.12 higher.  
23 We're showing this as a negative to indicate the  
24 benefits associated with flowing the revenues, but  
25 relative to our projected fuel cost filings, just



1 looking at the revenues, the factor would be up \$2.12.

2 The third column, that's titled Less System  
3 Average Fuel and Purchased Power again goes to using a  
4 very conservative proxy on both the SO2 replacement  
5 costs as well as using the combined aggregate system  
6 average fuel as well as the total purchased power  
7 that's in our projection. This is right off of  
8 Line 20 in the Schedule E-1s in Ms. Zwolak's  
9 testimony, but effectively incorporates that \$20.87  
10 combined system fuel and purchased power production  
11 cost type number, and applied to the total FMPA energy  
12 associated with the 150 megawatts and 100% load  
13 factor. And if you took those revenues and pulled out  
14 these higher costs, then effectively you still  
15 generate a benefit of 35 cents per 1,000 kWh.

16 Q So which number on the table represents the  
17 impact on a 1,000 kilowatt hour residential bill?

18 A They both do. The middle column reflects  
19 just the revenues without any crediting of what the  
20 incremental costs are. The third column reflects a  
21 crediting, if you would, if we were to separating what  
22 would that reduction be in terms of expense. Where  
23 we're really at, if you look at the incremental fuel  
24 out of the assigned units it's something that's closer  
25 to 50, 55 cents. That's the difference.

1                   **COMMISSIONER DEASON:** Could you repeat that?  
2     You're comparing the 35 to 55?

3                   **WITNESS HERNANDEZ:** Commissioner Deason, the  
4     55 -- the 50 to 55, it's approximately that number, is  
5     if you looked at what the true incremental fuel costs  
6     of the four units assigned to the transaction, that's  
7     Gannon 5 and 6, Big Bend 2 and 3 versus using the  
8     higher rate of the combined total system average fuel,  
9     not incremental fuel, but average fuel, and the total  
10    purchases associated with our total system. And so we  
11    use that number just to indicate that there's still  
12    net benefits even if you consider average fuel and  
13    total purchases.

14                  **COMMISSIONER DEASON:** Why do you have zero  
15    for current treatment?

16                  **WITNESS HERNANDEZ:** Because in the absence  
17    of knowing where we're going to actually end up in  
18    terms of earnings for year 2000 and subject to a  
19    review, that ultimately wouldn't get probably resolved  
20    until 2001. There would be a zero impact to the  
21    fuel -- well, actually all the cost recovery clauses.  
22    To the extent that we pulled all of the \$44 million of  
23    revenues, the bill would actually increase by the  
24    amount that we're showing here. We show it as zero  
25    because we showed the benefits as a negative, but our

1 projections already include those benefits. Another  
2 way would to have been shown a zero differential in  
3 Column 1 -- I'm sorry, Column 2 and shown a positive  
4 increase on the bill. We chose to represent it a  
5 different way.

6 Q (By Mr. Keating) Just for clarification,  
7 does Column 3 reflect the difference between the  
8 revenues collected and the estimated cost of the  
9 transaction to the ratepayers based on system average  
10 fuel?

11 A Yes.

12 Q Okay. Finally, on the last page of that  
13 exhibit that I handed to you, this exhibit depicts the  
14 incremental cost of the FMPA sales; is that correct?

15 A Yes.

16 Q Do you know what the revenues are for that  
17 same period, the January 2000 through March 2001?

18 A It's roughly \$44 million.

19 Q I just have a few more questions. Could you  
20 briefly describe the purchased power agreement that  
21 TECO has with Hardee Power Partners?

22 A To the best I can, I'm just aware of -- I  
23 don't know the details of the contract. The agreement  
24 is for a purchase of 75 megawatts nominal capacity  
25 generated from a GE-7EA machine. It fits into the

1 existing infrastructure, the space, if you will, at  
2 the existing Hardee site. It's characterized as a  
3 CT-2B which sits right next to its sister unit, CT-2A,  
4 configured in a way that to the extent the economics  
5 makes sense for Tampa Electric and we opt to complete  
6 the second phase build-out of the second combined  
7 cycle unit, that unit facilitates that ultimate  
8 build-out. We have not yet committed for the full  
9 build-out of a combined cycle unit. We simply  
10 indicated to Seminole Electric and to Hardee Power  
11 Partners our intent to do a phased construction of  
12 that combined cycle by first putting in the CT-2B.  
13 The nominal 75 megawatts capacity is expected to be  
14 available around mid-May of next year.

15           It is -- because it lines up with the  
16 existing agreement that was reviewed by this  
17 Commission back in 1989 and 1990, it effectively is  
18 required only in an amendment to the existing  
19 agreement simply because of the utilization of the  
20 resources we talked about. Tampa Electric has an  
21 unconstrained first call. Seminole has a secondary  
22 call. Different configuration than the first 295  
23 megawatts in capacity.

24           The agreement commences with the commercial  
25 operation date, as I mentioned, of mid-May of next

1 year and goes through the end of -- it's a 12 year  
2 deal. Let me get the numbers right. To the end of  
3 2012, I believe, if that's right. But effectively it  
4 lines up with the existing agreement in terms of the  
5 terms and conditions.

6 The capacity and energy payments were  
7 prescribed by the original agreement and were modified  
8 slightly due to the supplemental sale to Seminole  
9 Electric to the extent that Tampa Electric doesn't  
10 need it. So there's slight variations. Again, all  
11 that was reviewed by FERC; a cost based transaction  
12 and approved by FERC, and as in place and we're  
13 expecting to have that capacity available for our  
14 system by mid-May of next year.

15 Q And when did TECO enter into that contract?

16 A There were discussions earlier this year. I  
17 believe that contract or amendment is in Mr. Brown's  
18 testimony, but Mr. Brown can answer that question.

19 Q Okay. How would you describe the wholesale  
20 power market in terms of pricing when TECO entered  
21 into the Hardee Power Partners contract?

22 A The pricing of the market?

23 Q Yes.

24 A I'd say, again, because of the things you've  
25 heard earlier, because of the situation with capacity,

1 physical capacity in the state of Florida as well as a  
2 tightening operating and planning reserves, at least  
3 during the next couple of years, market pricing for  
4 short term purchases are definitely higher than what  
5 they were expected to be a couple of years ago. The  
6 benefit of utilizing the Hardee Purchased Power  
7 Agreement is that if you were to compare the terms and  
8 conditions that were established back in '89 and '90  
9 and that became effective in 1993 with the commercial  
10 operation date of the first combined cycle in CT-2A,  
11 the rates are even slightly lower when you do a rate  
12 comparison.

13 So, relative to the market I think it's a  
14 great deal.

15 Q So how has the market price for wholesale  
16 power changed since TECO entered into the wholesale  
17 agreement with FMPPA?

18 A Well, certainly for Tampa Electric's system,  
19 our planning reserves got tighter, principally due to  
20 greater load growth, retail load growth than what we  
21 expected for year 2000. The capacity in our existing  
22 system is comparable to what we thought it was going  
23 to be. It's simply that that growth in retail has  
24 driven our reserve margins closer to our minimum.  
25 That had one impact.

1           From a state perspective, looking at the  
2           state operating reserves and the planning reserves,  
3           they have come down as well. Tampa Electric, probably  
4           relative to its size probably had a greater impact of  
5           the higher retail load growth but certainly our  
6           condition in our system as well as the external  
7           conditions, the Florida market, have created a  
8           situation where the market prices are higher and  
9           capacity is a little more scarce.

10           Q     Could you explain why -- TECO's seeking cost  
11           recovery for four other purchased power agreements; is  
12           that correct?

13           A     I'm sorry. Is TECO?

14           Q     Is TECO seeking recovery of costs under four  
15           other purchased power agreements?

16           A     Yes, we are.

17           Q     And those agreements range from seven months  
18           to 15 months in length; is that correct?

19           A     Subject to check, I believe that's correct.

20           Q     Okay. Why has TECO entered into the shorter  
21           term contracts while at the same time entering into a  
22           12 year contract with Hardee Power Partners?

23           A     Again, part of it was timing. Secondary  
24           issue was the existence of an available infrastructure  
25           and agreement. The contract, as you'll hear later

1 from our witness Mark Ward -- the 12 year duration of  
2 the contract is cost-effective on the same basis that  
3 this Commission reviewed and approved the original  
4 agreement, and that's on a cumulative present worth  
5 revenue requirements. If you look on a short-term  
6 basis, the rates that are being charged are certainly  
7 less than what we think the market is over the next  
8 several years.

9 As the capacity in the state gets built up,  
10 either through other resources that are being added in  
11 the state, that will help suppress the market prices  
12 after the next three to four years, but that has all  
13 been factored into the cost-effectiveness study, as  
14 you'll hear later.

15 Q Just two more questions. If the Commission  
16 were to approve Staff's position on Issue 9 -- and  
17 this is jumping back. That is, if TECO is required to  
18 flow transmission revenues from their nonseparated  
19 nonbroker wholesale sales through the capacity clause,  
20 would that decision impact your proposed factors?

21 A For Tampa Electric the amounts of money that  
22 we're talking about are approximately \$100,000,  
23 \$110,000. It would not have a significant impact. It  
24 would be on the order of less than -- close to a  
25 penny, but not anything more. And that would just



1 simply be a shift from the fuel to the capacity cost  
2 recovery clauses.

3 Q And just to clarify, is your projection  
4 filing based on TECO applying the 20% shareholder  
5 incentive to any other types of sales other than what  
6 it currently applies the 20% incentive to?

7 A No.

8 Q Thank you.

9 MR. KEATING: I have no further questions.

10 COMMISSIONER DEASON: Redirect.

11 MR. WILLIS: I just have a couple.

12 REDIRECT EXAMINATION

13 BY MR. WILLIS:

14 Q Mr. Hernandez, does this Commission have a  
15 policy which has encouraged sales such as the FMPA  
16 sale?

17 A Yes, it does.

18 Q Is Tampa Electric sale to FMPA consistent  
19 with that policy?

20 A Yes, it is.

21 Q Is making cost-effective wholesale sales  
22 which provide revenues greater than incremental costs  
23 of making such sales good for retail customers?

24 A Absolutely.

25 Q In 1985 did this Commission give Tampa

1 Electric a specific incentive to make off-system  
2 sales?

3 A In 1995?

4 Q In 1985.

5 A Yes, it did. And that was coincident with  
6 the construction of the Big Bend 4 unit that came in  
7 line in February of that year, I believe. The  
8 Commission basically awarded Tampa Electric for the  
9 next three years or so to sell its available capacity  
10 in excess of what it needed for our retail reserve  
11 margin criteria at the time to sell to the market and  
12 to receive revenues to offset the construction of that  
13 unit until our system grew into it.

14 Q Has Tampa Electric worked hard to optimize  
15 off-system sales?

16 A Absolutely. Up until the last couple of  
17 years, as our system continued to grow into our supply  
18 side resources, Tampa Electric at one point, probably  
19 had over 50% or close to it of the economy sales  
20 market in the state of Florida.

21 Q Is Tampa Electric Company's proposal with  
22 respect to FMPA fair to all concerned?

23 A Yes, it is.

24 COMMISSIONER CLARK: Mr. Willis, can I  
25 interrupt you just a minute? I do have a question I

1 want to ask and it may be that it's appropriate to do  
2 redirect.

3 Mr. Hernandez, can you explain to me how it  
4 is that there's apparently a disparity in treatment  
5 with respect to economy sales in the sense that FPC  
6 and FPL, as I understand some of the testimony, they  
7 only apply the split the savings when it is broker,  
8 the hour to hour sale as I understand it. Yet, you  
9 and Gulf have done it on other economy sales. Where  
10 was the breakdown in understanding? Why was there not  
11 uniformity to your knowledge?

12 **WITNESS HERNANDEZ:** I'm reluctant to speak  
13 for the other companies, Commissioner Clark, but in my  
14 opinion it's the same resources being utilized, in a  
15 certain extent off broker transactions where you're  
16 not using an automated system and you got to actually  
17 physically contact, either by phone or go talk with  
18 people in order to entire into those type of  
19 transactions. Even though they're still split the  
20 savings, it takes more work.

21 **COMMISSIONER CLARK:** Do you have a specific  
22 order where it was indicated that it was acceptable  
23 for beyond broker sales?

24 **WITNESS HERNANDEZ:** No. But at the same  
25 time I can't recall one that said you couldn't or

1 shouldn't do that.

2           **MR. WILLIS:** Commissioner Clark, the orders  
3 with respect to that refer to the type of transaction  
4 as opposed to the medium by which the transaction is  
5 consummated and that's how -- we can find those if you  
6 want.

7           **COMMISSIONER CLARK:** That would be helpful  
8 and if you could address it when you come back on  
9 rebuttal.

10           **MR. STONE:** Commissioner Clark, if I may, if  
11 you were to look at Exhibit 26, Gulf has provided a  
12 narrative in response to that interrogatory that may  
13 be helpful in that regard.

14           **COMMISSIONER CLARK:** Okay.

15 **BY MR. WILLIS:**

16           **Q** With respect to questions that Commissioner  
17 Clark asked you, should there be a difference in  
18 treatment with respect to the incentive by virtue of  
19 the medium by which the deal is struck as opposed to  
20 the basic fundamentals of the transaction?

21           **A** No, there should not be a difference.

22           **Q** Okay. Going back to the FMPA transaction,  
23 would separation provide a severe penalty to Tampa  
24 Electric?

25           **A** Yes, it would.

1           **MR. WILLIS:** No further questions, and I  
2 would move the admission of Exhibit 30.

3           **COMMISSIONER DEASON:** Without objection  
4 Exhibit 30 is admitted.

5           (Exhibit 30 received in evidence.)

6           **MR. KEATING:** Staff would move the admission  
7 of Exhibit 31.

8           **COMMISSIONER DEASON:** Without objection  
9 Exhibit 31 is admitted.

10          (Exhibit 31 received in evidence.)

11          **COMMISSIONER DEASON:** Let's go forward.

12          **MR. WILLIS:** We call Mr. Black.

13                                 - - - - -

14                                 **CHARLES R. BLACK**

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

18                                 **DIRECT EXAMINATION**

19          **BY MR. WILLIS:**

20           **Q**     Would you please state your name and  
21 address.

22           **A**     My name is Charles R. Black. My address is  
23 702 North Franklin Street, Tampa, Florida. Zip code,  
24 33602.

25           **Q**     Did you prepare and cause to be prefiled in

1 this docket prepared direct testimony of Charles R.  
2 Black?

3 A Yes, I did.

4 Q Do you have any additions or corrections to  
5 that testimony?

6 A No.

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

10 A Yes, they would.

11 MR. WILLIS: We request that Mr. Black's  
12 testimony be inserted in the record as though read.

13 COMMISSIONER DEASON: Without objection it  
14 shall be so inserted.

15

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BLACK

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

A. My name is Charles R. Black. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President-Energy Supply for Tampa Electric Company ("Tampa Electric" or "company").

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

A. I graduated from the University of South Florida in August 1973 with a Bachelor of Science degree in Engineering, majoring in Chemical Engineering. I am a Registered Professional Engineer in the State of Florida. I began my career with Tampa Electric in September 1973 as a staff engineer in the Production Department. Between 1973 and 1989, I held various engineering and management positions in the Production Department, Power Plant Engineering Department, and the Budget Department.

1 In March of 1989, I joined our affiliated company, TECO  
2 Power Services as Director Engineering and Construction.  
3 In December of 1990, I was elected Vice President of  
4 Engineering and Construction. In December of 1991, I  
5 returned to Tampa Electric as Vice President of Project  
6 Management. In December 1996 I assumed my present role  
7 as Vice President, Energy Supply.  
8

9 Q. Have you previously testified before this Commission?  
10

11 A. Yes. I testified in support of the prudence of Polk Unit  
12 One in Docket No. 960409-EI and in support of cost  
13 estimates associated with the proposed flue gas  
14 desulfurization system in Docket No. 980693-EI.  
15

16 Q. What is the purpose of your testimony in this proceeding?  
17

18 A. The purpose of my testimony is to provide support for a  
19 Commission determination that Tampa Electric had in place  
20 reasonable procedures and requirements that should have  
21 prevented the accident during the maintenance outage of  
22 F. J. Gannon ("Gannon") Unit 6, and the company acted  
23 prudently in its actions following the accident on April  
24 8, 1999. I will provide an overview of events related to  
25 the Gannon Unit 6 accident, an overview of system



1 recovery for Gannon Units 1 through 6, and a current  
2 assessment of Gannon Unit 6.

3  
4 Q. Have you prepared an exhibit to support your testimony?

5  
6 A. Yes I have. My Exhibit No. 32 (CRB-1) was prepared  
7 under my direction and supervision and consists of two  
8 documents.

9  
10 Q. Please describe the Gannon Unit 6 accident.

11  
12 A. On April 8, 1999, an explosion occurred on the  
13 turbine/generator floor at Tampa Electric's Gannon Unit  
14 6, a 375-megawatt generator. At the time of the  
15 accident, Gannon Unit 6 was not operational and was in  
16 the third week of an eight week planned maintenance  
17 outage. The accident occurred as hydrogen, used to cool  
18 the unit's generator during normal operations, exploded  
19 when one of four generator maintenance access covers was  
20 removed prior to purging the hydrogen from the unit. The  
21 accident resulted in three fatalities and injuries to 45  
22 employees and sub-contractors. The explosion damaged  
23 Units 5 and 6 and caused the immediate emergency shutdown  
24 of the five Gannon units that were operating at the time  
25 of the accident.

1 Q. Does Tampa Electric have sufficient safety practices and  
2 procedures in place to prevent against accidents such as  
3 the one which occurred at Gannon Station?  
4

5 A. Yes. One of the company's highest priorities is to  
6 provide a safe and healthy work environment for all  
7 employees and assure that employees have the knowledge,  
8 skills, and equipment to perform their jobs safely. The  
9 company has in place rigorous and specific procedures for  
10 maintenance outage activities. These safety procedures  
11 are designed to be in compliance with OSHA and industry  
12 standards, including ANSI standards, National Electric  
13 Safety Code and others.  
14

15 In this case, prior to beginning any work, the company's  
16 safe work practices require the supervisor of the crew to  
17 conduct a job briefing with the crew before the start of  
18 each job. The briefing requires the supervisor to cover  
19 the hazards associated with the job, work procedures,  
20 special precautions, energy source controls, and personal  
21 protective equipment requirements for maintenance  
22 procedures that are to be performed.  
23

24 Further, the company's safe work practices require that  
25 before work is performed on a generator it should have

1        been purged of hydrogen and then tested and proper  
2        clearance should have been obtained in accordance with  
3        the tagging procedures applicable to Energy Supply.  
4        Employees undergo safety training routinely on all topics  
5        associated with the various power plant maintenance  
6        activities and the company's safe work practices.

7  
8        Q.    Was the crew assigned to Gannon Unit 6 experienced and  
9        trained?

10  
11       A.    Yes.    The crew foreman and his maintenance crew were  
12       highly experienced. All but one member of the crew were  
13       journeyman power plant mechanics who had worked together  
14       for many years. The journeymen were in a specially  
15       designated job classification that denoted and provided  
16       extra compensation for their specialized skills in heavy-  
17       duty power plant maintenance work. As of April 1999, the  
18       number of years that the members of the crew had  
19       performed in the classification of power plant  
20       maintenance mechanic ranged from 6.5 years to 21 years.  
21       For the crew assigned to this job, the work they were to  
22       perform on Unit 6 was routine.

23  
24       Q.    Did Tampa Electric have training procedures in place to  
25       ensure employees are properly trained?

1  
2 **A.** Yes. Company employees are provided various forms of  
3 training. Core training includes annual safety and  
4 environmental training. This training covers tagging  
5 procedures as well as confined space procedures and  
6 hazardous material training. The company also provides  
7 periodic CPR and first-aid training. In addition to core  
8 training, the company requires periodic refresher  
9 training, safety meetings, and on-the-job training.

10  
11 **Q.** Was the employee who removed the access cover of the  
12 generator properly trained?

13  
14 **A.** Yes. The employee who removed the access cover was a  
15 production apprentice for six years. He had completed an  
16 outage at the company's Big Bend facility before he was  
17 assigned to the outage at Gannon. He had attended an  
18 annual two-day, safety and environmental refresher-  
19 training program and tagging procedures training within  
20 the year prior to the accident and other safety programs  
21 on specific topics throughout the years. He had  
22 extensive hours of on-the-job training and routinely  
23 attended safety meetings.

1 Q. Who made the decision to open the access cover of the  
2 generator?

3  
4 A. From the best the company has ascertained, the employee  
5 who opened the access cover made the decision based on  
6 his belief that it was safe to do so.

7  
8 Q. Did the company act prudently in performing maintenance  
9 on Gannon Unit 6 on April 8, 1999?

10  
11 A. Yes. The maintenance being performed when the explosion  
12 occurred was planned spring maintenance. Gannon Unit 6  
13 was taken out of service on March 26, 1999 for inspection  
14 and maintenance of the boiler, turbine and generator.  
15 Details of the planned maintenance activities have been  
16 provided to Staff in response to Interrogatory No. 35b  
17 and are included as Document 1 of my exhibit. This type  
18 of scheduled major maintenance is typically performed  
19 routinely in preparation for high system demands in the  
20 summer months. Gannon Unit 6 was originally scheduled to  
21 return to service on May 23, 1999.

22  
23 Q. Once the explosion occurred at Unit 6, how were Units 1  
24 through 5 impacted?

25

1   **A.**   Due to the quick response of the Gannon Station employees  
2           operating Units 1 through 5, they were able to implement  
3           a safe and orderly shutdown procedure and the company was  
4           able to minimize the amount of damage to the other units.  
5           Unit 5 sustained damage primarily due to the explosion  
6           from Unit 6 while the other four units suffered little or  
7           no damage.   Units 1 through 3 went back in service on  
8           April 10 and Unit 4 was back in service on April 12.  
9           Unit 5 was returned to service on May 16.

10

11   **Q.**   Please describe the procedures Tampa Electric employed  
12           for overall system restoration as a result of the Gannon  
13           6 accident.

14

15   **A.**   The company's immediate response and concern was for the  
16           safety of employees.   After the explosion, the units were  
17           shutdown without any significant problems.   The operators  
18           initially purged the hydrogen from the remaining  
19           generators to minimize the risk of any further fire or  
20           explosions.   To ensure the units could be returned to  
21           service safely, the damage assessment teams from within  
22           and outside the company began inspections as early as two  
23           hours after the accident.   Units 1 though 4 were safely  
24           returned to service as soon as these inspections were  
25           complete.

1  
2 Gannon Unit 5 received more direct physical damage to the  
3 electrical equipment since it is located adjacent to Unit  
4 6. All safety systems worked properly and the operators  
5 responded to ensure the safety of the employees and  
6 equipment. No damages occurred to the boiler or turbine  
7 as a result of the explosion. Detailed inspections were  
8 made on all of the equipment and structures immediately  
9 following the accident. Motors, switchgear, cables, and  
10 other equipment were repaired or sent out for inspection  
11 and cleaning. Equipment was secured to minimize damage  
12 from the elements. Details of the additional maintenance  
13 and repair activities beyond those contemplated in the  
14 outage have been provided to Staff in response to  
15 Interrogatory No. 35c and is provided in Document 2 of my  
16 exhibit.

17  
18 **Q.** What is the current status and assessment of Gannon Unit  
19 6?  
20

21 **A.** Gannon Unit 6 returned to full service on June 22, 1999.  
22 All of the originally planned maintenance was performed  
23 in addition to those activities that needed to be  
24 performed as the result of the explosion. Since the unit  
25 was returned to service, it has operated normally.

1

2 Q. Please summarize your testimony.

3

4 A. My testimony demonstrates that Tampa Electric Company  
5 took reasonable precautions to guard against an explosion  
6 of hydrogen gas during the maintenance outage of Gannon  
7 Unit 6, and the company acted prudently in performing  
8 maintenance on April 8, 1999. The company had sufficient  
9 safety practices and procedures in place to prevent  
10 against accidents such as the one that occurred. The  
11 crew assigned to Gannon Unit 6 were experienced and  
12 trained. The employee who opened the access cover made  
13 the decision based on his belief that it was safe to do  
14 so. After the accident occurred, the company was able to  
15 restore its system by taking prudent and reasonable  
16 actions to ensure the safety of its employees while  
17 completing all necessary maintenance and restoration of  
18 its units.

19

20 Q. Does this conclude your testimony?

21

22 A. Yes, it does.

23

24

25



1           **Q**       **(By Mr. Willis)** Did you have an exhibit  
2       which was prepared in support of your testimony,  
3       Mr. Black?

4           **A**       Yes.

5                   **MR. WILLIS:** Commissioner, I request that  
6       the documents attached to Mr. Black's prepared direct  
7       testimony be marked as a composite exhibit.

8                   **COMMISSIONER DEASON:** That will be Exhibit  
9       32.

10                   (Exhibit 32 marked for identification.)

11                   **MR. WILLIS:** I would just like to point out,  
12       with respect to Exhibit 32, just to avoid confusion,  
13       there is a document that was premarked CAB -- CRB-2  
14       that should have been CRB-1 because there is a  
15       separate CRB-2 in his rebuttal testimony.

16           **Q**       **(By Mr. Willis)** Would you please summarize  
17       your testimony.

18           **A**       Yes. Good afternoon, Commissioners. As you  
19       are all well aware on April 8, 1999 an unfortunate  
20       accident occurred during a maintenance outage of Tampa  
21       Electric's Gannon Unit No. 6. The accident occurred  
22       as hydrogen used to cool the generators during normal  
23       operation exploded when one of the four generator  
24       maintenance access covers was removed prior to the  
25       hydrogen being purged from that unit.

1           The accident resulted in three fatalities  
2           and injuries to 45 employees and subcontractors. The  
3           explosion damaged Units 5 and 6 and caused the  
4           immediate emergency shut down of all five Gannon units  
5           that were operating at the time of the accident.

6           My testimony describes the reasonable  
7           precautions that Tampa Electric took to guard against  
8           an explosion of hydrogen gas during the maintenance  
9           outage of Gannon 6 and explains that the company acted  
10          prudently in performing maintenance on that unit.

11          Safety is one of the company's highest  
12          priorities and we continually work to ensure that  
13          employees have the knowledge, skills and equipment to  
14          perform their job safely.

15          In the case of Gannon Unit No. 6, Tampa  
16          Electric had in place rigorous procedures for the  
17          maintenance outage activity as well as safe work  
18          practices requiring the crew supervisor to provide a  
19          detailed job briefing prior to the start of each job.

20          Our employees undergo safety training  
21          routinely on all topics associated with the various  
22          power plant maintenance activities and the company's  
23          safe work practices.

24          Our employees undergo annual core training  
25          covering tagging procedures, confined space procedures

1 and hazardous material training. This core training  
2 is augmented by periodic refresher training, safety  
3 meetings and on-the-job training. Tampa Electric also  
4 provides CPR and first aid training for our employees.

5           The crew foreman and maintenance crew  
6 performing the Gannon Unit 6 maintenance were highly  
7 qualified and experienced. The employee who actually  
8 removed the access cover had been a production  
9 apprentice for six years and had attended an annual  
10 two day safety and environmental refresher training  
11 program within the year prior to the accident. He had  
12 extensive hours of on-the-job training, and routinely  
13 attended safety meetings.

14           From the best information we have it appears  
15 that the employee who opened the access cover made the  
16 decision to do so based on his belief that it was safe  
17 to open the cover.

18           Tampa Electric acted prudently in performing  
19 maintenance on Gannon 6 on April 8th. That  
20 maintenance was planned spring maintenance performed  
21 on a routine basis. Once the accident occurred our  
22 employees responded quickly to implement a safe and  
23 orderly shut down of the units that were operating.

24           Units 1 through 4 were returned to service  
25 as soon as damage assessment teams had determined that

1 it was safe to do so. Units 1 through 3 were returned  
2 to service on April 10th. Unit 4 was back in service  
3 on April 12th. Unit 5 returned to service May 16th,  
4 and Gannon 6 returned to full service on the 22nd of  
5 June, 1999.

6 It is unfortunate that this accident  
7 occurred despite the reasonable precautions Tampa  
8 Electric took to avoid this type of occurrence. Our  
9 safety practices and procedures were sufficient and  
10 the crew assigned to the Gannon Unit No. 6 were  
11 experienced and well trained.

12 Finally, our post accident response was  
13 prudent and expedited with all six units being brought  
14 back into service as soon as we could safely do so.  
15 That concludes my summary.

16 **MR. WILLIS:** I tender the witness.

17 **COMMISSIONER DEASON:** Ms. Kaufman.  
18 Mr. McWhirter.

19 **CROSS EXAMINATION**

20 **BY MR. MCWHIRTER:**

21 **Q** Mr. Black, let me ask you a multiple choice  
22 question. Was the explosion caused by A, an act of  
23 God; B, the nonfeasance of an employee, or the act of  
24 an employee of Tampa Electric Company?

25 **A** The choice would be B.

1           Q     Do you know of any act by any customer of  
2 Tampa Electric Company that contributed to this  
3 explosion?

4           A     No, sir.

5           Q     Have there been any other explosions at the  
6 Gannon plant before this one?

7           A     What type? I'm not sure I understand the  
8 question. You mean similar to the hydrogen explosion?

9           Q     No. No. Just any explosions at all.

10          A     There had been a steam line that created a  
11 release of steam in the plant, I believe, back in  
12 1994.

13          Q     Any before that?

14          A     Not that I'm aware of.

15          Q     You personally investigated or supervised  
16 the investigation of this unfortunate accident?

17          A     My role was associated with the restoration  
18 of the unit and the return of those units safely and  
19 the care of the employees. I did not personally head  
20 up the investigation.

21          Q     From your personal observation of the  
22 circumstances -- and if you don't know from your  
23 personal observation or it wasn't reported to you in  
24 the due course of your function -- was the accident  
25 caused by the fact that the man was unscrewing the top

1 of this generator and hydrogen escaped and exploded?

2 That was the cause of it?

3       **A**     Based on the physical evidence that we  
4 reviewed it appears the cause of the accident was  
5 associated with the removal of an access cover on the  
6 generator and that access cover being removed prior to  
7 the time that hydrogen had been purged from the  
8 generator. When the cover had been removed it allowed  
9 the hydrogen to escape into the plant and at some  
10 point the hydrogen and air mixture found an ignition  
11 source and the explosion occurred.

12       **Q**     And at Page 9 on your testimony at Line 23,  
13 you say the accident was the result of an unfortunate  
14 miscommunication by a valued and dedicated employee  
15 and was certainly not any willful misconduct of  
16 anyone.

17       **A**     I'm sorry. I'm not with you. Could you  
18 repeat the reference again?

19       **Q**     On Page 9, Line 22. That's your testimony?

20       **A**     I think you may be looking at my rebuttal  
21 testimony.

22               **MR. WILLIS:** That's the rebuttal testimony,  
23 Mr. McWhirter.

24               **MR. MCWHIRTER:** Rebuttal. Okay. I  
25 apologize. Can I ask him about that at this time or

1 would you prefer I wait?

2 COMMISSIONER DEASON: If he's going to be  
3 coming back for rebuttal, we'll just wait.

4 MR. MCWHIRTER: I'd rather waive rebuttal  
5 and get it all over now.

6 MR. HART: We would not.

7 Q (By Mr. Mcwhirter) All right. Well, then  
8 I won't ask you that question until later. I perceive  
9 from the general tenor of your testimony that it is  
10 your opinion that any damages caused by this accident  
11 should be placed upon the consumers of Tampa Electric  
12 rather than the company. What is the rationale for  
13 that opinion?

14 A The request that the company has made is to  
15 recover the fuel and purchased power associated with  
16 the accident. Those costs are recoverable under the  
17 regulatory arrangement that we have with the  
18 Commission. We've not requested that all the costs,  
19 direct costs and other costs associated with the  
20 accidents, be recovered; simply that we believe the  
21 company did act in a prudent way and we had prudent  
22 procedures in place and we've managed the business,  
23 both the operation and maintenance of the business, in  
24 a prudent fashion and under the rules of the  
25 Commission fuel and purchased power is a recoverable

1 expense and that's my rationale.

2 MR. MCWHIRTER: I have no further questions  
3 of the witness.

4 COMMISSIONER DEASON: Mr. Burgess.

5 CROSS EXAMINATION

6 BY MR. BURGESS:

7 Q Yes, sir. Mr. Black, you just indicated  
8 that all not the costs are being sought for recovery.  
9 Do you mean that some of the costs are being accounted  
10 for below the line in base rates?

11 A I'm not sure as to the above the line below  
12 the line treatment, but there were direct costs  
13 associated with the accident that we've incurred.

14 Q That you're not seeking to be recovered  
15 through any type of rate recovery?

16 A Not that I'm aware of.

17 Q Well, is it your understanding that the only  
18 way to -- that they would not be included in rates  
19 would be is if they were included as some type of  
20 below the line treatment?

21 A No. By virtue of saying they're not being  
22 asked to be recovered I'm not saying that they're not  
23 covered by base rates. I'm saying they're not  
24 specifically being asked for recovery like the fuel  
25 and purchased power.



1           Q     You mean they're not just included in the  
2 fuel?

3           A     That's correct.

4           Q     Okay. Thank you. Is it your understanding  
5 that these Gannon units have been in the Tampa  
6 Electric rate base?

7           A     Yes.

8           Q     Since they've been in service?

9           A     Yes.

10          Q     And is it your understanding that -- are you  
11 aware at all of the stipulations that have been  
12 entered into surrounding the earnings of Tampa  
13 Electric Company over the last several years?

14          A     Generally familiar with it, yes, sir.

15          Q     Is it your understanding that Tampa Electric  
16 Company has earned between \$11.75 and \$12.75 in the  
17 last several years pursuant to those stipulations?

18          A     That's my general understanding.

19          Q     So then both in theory and in fact TECO has  
20 collected between \$11.75 and \$12.75 return to cover  
21 the risk associated with its investment in the Gannon  
22 Unit; is that correct?

23          A     That's the return that we've earned, yes,  
24 sir.

25               **MR. BURGESS:** Thank you, Mr. Black. That's

1 all that I have.

2 COMMISSIONER DEASON: Staff.

3 MR. KEATING: Staff has no questions. We  
4 would like to have an exhibit identified. I believe  
5 TECO can stipulate with Staff to have this exhibit  
6 moved into the record.

7 This exhibit is composed of the deposition  
8 of Mr. Black. It does not include the exhibits to  
9 that deposition, only the text transcript and it also  
10 includes TECO's response to Staff's Second Set of  
11 Interrogatories Nos. 21 through 27 concerning the  
12 explosion at Gannon.

13 COMMISSIONER DEASON: It will be identified  
14 as Exhibit 33.

15 (Exhibit 33 marked for identification.)

16 COMMISSIONER DEASON: Commissioners,  
17 questions? Redirect.

18 MR. WILLIS: No redirect. I move admission  
19 of Exhibit 32, I believe it was.

20 COMMISSIONER DEASON: Without objection  
21 Exhibit 32 is admitted.

22 (Exhibit 32 received in evidence.)

23 MR. KEATING: Staff would move 33.

24 COMMISSIONER DEASON: Without objection  
25 Exhibit 33 is admitted.

1 (Exhibit 33 received in evidence.)

2 **MR. WILLIS:** We call Mr. Brown.

3 **COMMISSIONER DEASON:** We're going to recess  
4 for lunch at this time. We will reconvene at 1:00.

5 (Thereupon, lunch recess was taken at  
6 12:30 p.m.)

7 - - - - -

8 (Transcript continues in sequence in  
9 Volume 4.)

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