188

1 BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

2

3 In the Matter of DOCKET NO. 060001-EI

4 FUEL AND PURCHASED POWER

COST RECOVERY CLAUSE WITH

5 GENERATING PERFORMANCE INCENTIVE

FACTOR.

6 ---------------------------------

7 PETITION TO RECOVER NATURAL GAS DOCKET NO. 060362-EI

STORAGE PROJECT COSTS THROUGH

8 FUEL COST RECOVERY CLAUSE, BY

FLORIDA POWER & LIGHT COMPANY.

9 ---------------------------------

10 PETITION FOR AUTHORITY TO DOCKET NO. 041291-EI

RECOVER PRUDENTLY INCURRED

11 STORM RESTORATION COSTS RELATED

TO 2004 STORM SEASON THAT

12 EXCEED STORM RESERVE BALANCE, BY

FLORIDA POWER & LIGHT COMPANY.

13 \_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_/

14 ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE

A CONVENIENCE COPY ONLY AND ARE NOT

15 THE OFFICIAL TRANSCRIPT OF THE HEARING,

THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

16

VOLUME 2

17 Pages 188 through 406

18

PROCEEDINGS: HEARING

19

BEFORE: CHAIRMAN LISA POLAK EDGAR

20 COMMISSIONER J. TERRY DEASON

COMMISSIONER ISILIO ARRIAGA

21 COMMISSIONER MATTHEW M. CARTER, II

COMMISSIONER KATRINA J. TEW

22

DATE: Monday, November 6, 2006

23

TIME: Commenced at 9:30 a.m.

24 Adjourned at 5:08 p.m.

25

189

1 PLACE: Betty Easley Conference Center

Room 148

2 4075 Esplanade Way

Tallahassee, Florida

3

4 REPORTED BY: MARY ALLEN NEEL, RPR, FPR

5

6 PARTICIPATING: (As heretofore noted.)

7

8

9 \* \* \*

10

11

12 I N D E X

13 WITNESSES

14 NAME PAGE

15 GERARD J. YUPP

16 Continued Cross-Examination by Mr. McWhirter 192

Cross-Examination by Ms. Bennett 217

17 Redirect Examination by Mr. Butler 219

18 W. E. GWINN

19 Prefiled Testimony Inserted 224

20 PAMELA SONNELITTER

21 Prefiled Testimony of 4/3/06 Inserted 237

Prefiled Testimony of 9/1/06 Inserted 251

22

GEORGE BACHMAN

23

Direct Examination by Mr. Horton 256

24 Prefiled Testimony Inserted 259

25

190

1 CONTINUED INDEX

2 NAME PAGE

3

ROBERT CAMFIELD

4

Direct Examination by Mr. Horton 263

5 Prefiled Testimony Inserted 268

Cross-Examination by Ms. Bennett 295

6

MARK CUTSHAW

7

Direct Examination by Mr. Horton 302

8 Prefiled Testimony Inserted 305

Cross-Examination by Ms. Bennett 308

9

CHERYL MARTIN

10

Direct Examination by Mr. Horton 310

11 Prefiled Testimony of 2/26/06 Inserted 313

Prefiled Testimony of 8/8/06 Inserted 315

12 Prefiled Testimony of 10/26/06 Inserted 317

13 R. H. BALL

14 Direct Examination by Mr. Badders 322

Prefiled Testimony of 3/1/06 Inserted 326

15 Prefiled Testimony of 8/8/06 Inserted 336

Prefiled Testimony of 9/1/06 Inserted 347

16 Cross-Examination by Ms. Christensen 357

Cross-Examination by Mr. McWhirter 358

17 Cross-Examination by Mr. Butler 368

18 RHONDA J. MARTIN

19 Prefiled Testimony of 8/8/06 Inserted 372

Prefiled Testimony of 9/1/06 Inserted 375

20

L. S. NOACK

21

Prefiled Testimony of 4/3/06 Inserted 385

22 Prefiled Testimony of 9/1/06 Inserted 393

23 TERRY A. DAVIS

24 Prefiled Testimony of Terry A. Davis Inserted 399

25 CERTIFICATE OF REPORTER 406

191

1 EXHIBITS

2

NUMBER I.D. ADMTD.

3

4 11 221

5 12 221

6 13 221

7 14 221

8 15 223

9 17 223

10 20 321

11 21 321

12 22 321

13 23 370

14 24 370

15 25 371

16 26 371

17 27 371

18 28 384

19 29 384

20

21

22

23

24

25

192

1 (Transcript follows in sequence from

2 Volume 1.)

3 Thereupon,

4 GERARD J. YUPP

5 called as a witness on behalf of Florida Power & Light

6 Company, continues his sworn testimony as follows:

7 CONTINUED CROSS-EXAMINATION

8 BY MR. McWHIRTER:

9 Q. A swap is a financial transaction; is that

10 correct?

11 A. That's right.

12 Q. And a collar is a financial transaction?

13 A. Yes, it can be, yes.

14 Q. And when you engage in the hedging, do you do

15 it in one of the commodity exchanges, or do you do it

16 over the counter?

17 A. Predominantly over the counter.

18 Q. Do you deal over the counter with any

19 affiliated companies of Florida Power & Light?

20 A. No, we do not.

21 Q. If the Commission had the duty to determine

22 whether a hedging program was prudent or imprudent, give

23 me an example of some kind of hedge that you would deem

24 to be imprudent.

25 A. From a utility perspective, I think hedges

193

1 that would be put in place purely at, let's say, trying

2 to save the customer money, and as I explained in my

3 summary, trying to outguess the market to return savings

4 to the customers, those would be in my opinion imprudent

5 hedging transactions.

6 The bottom line is, we don't know where the

7 market is going to go. And in order to execute a

8 prudent hedging program, you need to be well

9 disciplined, you need to follow the plan, so to speak,

10 and it does have to be independently controlled. But I

11 think "well disciplined" is the right term.

12 And there may be indications that the market

13 is heading in a different direction, and it's fine to

14 take that into account, and I think your hedging program

15 can be adjusted to take that into account with different

16 types of instruments to limit your exposure.

17 But to see the market moving in a different

18 direction and all of a sudden change your strategy I

19 think could be, in reference to your question,

20 Mr. McWhirter, deemed to be not prudent, because we

21 cannot guess where the market is going to go. It could

22 change tomorrow and start going back up again. So it's

23 the transactions that are speculative in nature that I

24 would say are not prudent.

25 Q. How do you determine whether a transaction was

194

1 speculative or not speculative?

2 A. Well, I guess that's the difficult part. But

3 I think probably -- and from what we file each year, I

4 think you can see a certain pattern with our results

5 where we weren't in and out of transactions on a

6 frequent basis, in other words, changing the percentages

7 of what we hedged. I mean, we develop our plan in the

8 beginning of -- generally in the beginning of the

9 previous year, and we execute that hedge program

10 throughout the year to get to our desired percentages,

11 and we don't vary a lot from that. Again, we're well

12 disciplined in our approach.

13 And so it would be difficult to see -- I think

14 it would be difficult to determine whether somebody was

15 in the market purely speculating, but I think you would

16 see a lot more swings in their percentages, maybe a lot

17 more volume traded in their percentages as they try to

18 beat the market. But again, it's probably difficult to

19 determine that.

20 Q. Under your hedging program, do you have

21 minimum and maximum percentages that you hedge at

22 different times of the year for, say, delivery -- if

23 you're hedging in August for delivery next June, do you

24 have a specified minimum or maximum percentage you use

25 in August 2006 for June 2007 acquisitions?

195

1 A. We generally will have a target percentage of

2 what we determined through management approval and

3 everything. We have a target percentage that we're

4 looking at for the next recovery period. We generally

5 will shape that.

6 Obviously, there are more volatile times than

7 others, such as the winter period versus summer period,

8 although with recent hurricane events and everything,

9 summer has become very volatile also. But, yes, we do

10 have target percentages that we're looking at and

11 tolerance bands around those target percentages to where

12 it's acceptable to be -- you are considered to be in

13 line with what the plan was if you are within that

14 tolerance band.

15 And the other point I'll make on that is -- or

16 other note I'll make on that is that we do engage in

17 rebalancing our hedge positions on a fairly frequent

18 basis. Depending on where fuel prices are moving, we

19 will look not necessarily to change percentages or to

20 change what our plan is, but to rebalance our positions

21 around where fuel prices are going and what our

22 projections or new projections would be from a move in

23 fuel price. And by projections, I mean fuel

24 requirements.

25 Q. Would you look at Appendix 1 to your

196

1 testimony, page 3? This is your September testimony.

2 A. Yes. Page 3?

3 Q. Yes, sir.

4 A. Yes.

5 Q. About --

6 MR. BUTLER: I'm sorry, Mr. McWhirter. Just

7 to be clear, for me at least, you're referring to the

8 page that begins, "FPL projected dispatch costs and

9 projected availability of natural gas"?

10 MR. McWHIRTER: That is correct, January

11 through December.

12 BY MR. McWHIRTER:

13 Q. Look at natural gas dispatch price. What does

14 that mean?

15 A. That is the dispatch price of natural gas that

16 we project. And by dispatch price, we meant it is the

17 commodity cost with variable transport rolled into that.

18 We do not dispatch our system with a fixed component of

19 transportation included, so our dispatch price for

20 natural gas includes commodity plus a variable transport

21 component to the burner tube.

22 Q. What are the -- you don't hedge in your

23 transportation costs, do you, or do you?

24 A. I'm not sure what I follow by hedging --

25 Q. Well, the NYMEX quotes prices at Henry Hub,

197

1 and you have a cost to transport the gas from Henry Hub

2 to wherever your generator is located, at the gateway.

3 A. Right.

4 Q. I call that the transportation price. What do

5 you call it? Basis?

6 A. No. You are correct. That is the

7 transportation cost. No, we do not hedge

8 transportation.

9 And there are two types of transportation.

10 There is obviously the fixed demand charge, which is a

11 sunk cost, which is what we will pay the transporter or

12 gas pipeline regardless of whether we use it or not.

13 That is our firm transportation. And then there's a

14 variable component of moving gas under firm

15 transportation.

16 Q. Looking at those four lines for your different

17 interstate pipelines, January through December, how do

18 those numbers that you have in your testimony compare to

19 the Henry Hub prices for the same periods? Are they

20 more or less?

21 A. How do they compare to the Henry Hub price

22 that was used to generate these prices?

23 Q. Yes, sir.

24 A. Or the NYMEX price, I should say.

25 Q. Well, you've got a commodity price and a

198

1 transportation price, and I want to know how -- say your

2 price for March is $11.25 on FGT per MM/Btu. How does

3 that compare to the NYMEX plus your fixed transportation

4 cost? Is that more or less?

5 A. That 11.25 would be more than the NYMEX

6 commodity price. How much more I don't know off the top

7 of my head here, but it would be more. Now, the other

8 thing to keep in mind, these projected dispatch costs do

9 not include the firm transportation demand charge, only

10 the variable component.

11 Q. I see. I'm sorry, but I have to ask you to

12 explain again the differential between the firm

13 transportation and the variable component.

14 A. Well, as part of our firm transportation

15 arrangements with either pipeline, FGT or Gulf Stream in

16 our case, we pay a demand charge, which is a fixed fee

17 for the amount of volume that we have as firm capacity

18 on either pipeline. And then to move gas under firm

19 transportation, there is variable transportation rates,

20 which is commodity and fuel.

21 And so in this particular table here, what you

22 see in firm FGT would be the commodity price, or our

23 NYMEX price, with a variable component added to it,

24 which would be our dispatch price. Now, under nonfirm

25 FGT, there would be an additional transport component

199

1 which we would consider interruptible transport.

2 So to the extent that I use all of the firm

3 transportation capacity that I have on either pipeline

4 to meet my requirements, my system requirements, we do

5 project that there is interruptible transport that may

6 be available on a day-to-day basis, and that's where you

7 see higher prices. As compared in the example that you

8 gave of 11.25 in March for firm FGT, dollar per MM/Btu,

9 you can see that nonfirm is at 11.68.

10 So that would be a case where there's an

11 interruptible transport rate that we're estimating what

12 that would be, and we put that into our model to say,

13 "Okay. Even given that extra interruptible transport

14 rate, would the system dispatch economically," and take

15 that additional gas.

16 Q. Do you use this number to lock in your hedge

17 percentages?

18 A. We do not use -- well, let me ask for a

19 clarification. Do we use what number to lock in our

20 hedge percentages?

21 Q. Well, let's take the 11.25 for March of 2007.

22 How do you use that number in connection with your

23 hedging operations?

24 A. Well, basically, that number -- and as a

25 footnote, this particular table was developed from

200

1 August 7th forward curve prices, which was the curve

2 that went into our September 1st filing.

3 But where this number would be used is, as it

4 would on a week-to-week basis, we develop projections on

5 a week-to-week basis, given updated forward curve

6 prices. And so these prices would go into developing

7 our fuel requirements, natural gas and fuel oil, for the

8 subsequent period or for the period that we're in. We

9 continually rebalance. And that is then the main driver

10 of our hedge percentage, so to speak. So as we update

11 our fuel burn requirements on a weekly basis, our hedge

12 percentages and whether we're in tolerance to what was

13 approved by management as the hedge plan is based on

14 those new requirements.

15 So I guess the long story, these prices are

16 used to develop fuel burn projections, which then is

17 what we are hedging based upon those fuel burn

18 projections.

19 Q. So you use the 11.25 number as what you would

20 go out into the over-the-counter market to buy --

21 A. No. We would -- I guess to clarify it better,

22 assuming 11.25 was put in the model to dispatch our

23 system and that resulted in a gas burn of 100,000

24 MM/Btu, if our hedge program bottom line intent for this

25 period of time was to be 50 percent hedged, then in this

201

1 case, the 100,000 MM/Btu that was generated by using

2 this fuel price would result in a hedge program

3 guideline of 50,000 MM/Btu, let's say, for March of the

4 period. And so we would hedging up to the 50,000 MM/Btu

5 to be within tolerance of our hedge program.

6 It has nothing to do with the price that is

7 shown here. We hedge based on what the prices generate

8 as our fuel requirements and what our agreed-upon hedge

9 percentages are.

10 Q. But you would use that price to determine what

11 you would pay -- if you were in the 50 percent criteria,

12 what you would pay -- what you would look for to

13 purchase gas in the futures market; is that correct?

14 A. Well, at that particular point in time, that

15 may be the price that -- if we were to rebalance, or

16 even were in the process of getting up to the original

17 hedge percentages, that may in fact be the price that we

18 would be hedging at. But it does take some time to

19 rebalance and to actually get to the appropriate level

20 of hedges for whatever the agreed-upon percentages were

21 for us.

22 So price does change on a day-to-day basis,

23 and it may not necessarily be at, in this case, whatever

24 the commodity underlying 11.25 was. It may not be that

25 price at the time that we execute the hedge.

202

1 But that's where we're not -- we are not price

2 guessing or speculating. We have a target percentage to

3 meet, and we are going to meet that. And depending on

4 what the outcome or revised fuel burn projections are

5 based on latest prices, we are going to go hedge to the

6 right percentage given those requirements.

7 Q. And each month as you approach the consumption

8 date, I would imagine each month your hedging percentage

9 increases to a maximum?

10 A. When we are originally hedging -- and we can

11 take 2006, for example, for 2007. Our original hedge

12 program in the '06 period probably begins sometime in

13 March, and we hedge across a pretty significant period,

14 let's say an eight-month period through October, if that

15 is in fact eight months. But once we agree on our

16 target hedges for '07 period, then we would begin in

17 early 2006, and we would begin hedging over a period of

18 time to get ourselves to the appropriate level.

19 Q. Is the appropriate level confidential

20 information, or can you give us some idea of what the

21 percentages are?

22 A. All of our hedge percentages we do keep

23 confidential.

24 Q. All right. You indicated on page 19 of your

25 September 1 testimony at line 10 that through the month

203

1 of July, you had realized losses of approximately

2 $186 million to that point in time. Can you give us an

3 update as to the realized losses to this point in time

4 in 2006?

5 A. Yes. I do have an update through September.

6 I do not have the final October numbers yet, but through

7 September, we were at $262 million realized losses.

8 Q. And if you wanted to determine the impact on

9 the customers, you would divide 262 million by what you

10 -- 109 million megawatt-hour sales that you make each

11 year, so your hedging losses would amount to -- well,

12 I've got my calculator here.

13 MR. BUTLER: I would ask Mr. McWhirter to

14 identify the source he's referring to for his

15 kilowatt-hour sales.

16 BY MR. McWHIRTER:

17 Q. On E1 that Ms. Dubin talked about earlier, I

18 believe your anticipated annual retail sales is in the

19 area of 109 million megawatt-hours, is that correct?

20 A. (Examining document.)

21 Q. Look at page 38. There are a lot of -- the

22 numbering system starts, but it's Schedule E1 on

23 Appendix 2.

24 A. Appendix 2, Schedule E1?

25 Q. Yes. And on line 24, you anticipate system

204

1 megawatt-hour sales to be 108.1 million megawatt-hours?

2 A. Yes, that is the number that is there.

3 Q. And so -- a megawatt-hour is the same as 1,000

4 kilowatt-hours?

5 A. Yes, sir.

6 Q. So if you divided $262 million by 108,

7 according to my calculations, subject to check, for

8 every thousand kilowatt-hours of consumption, it would

9 cost $2.43 more because you hedged in 2006 than if you

10 had not hedged; is that correct?

11 A. I'm not 100 percent sure about your

12 calculation, but what I can say is, yes, with losses,

13 with realized losses, it will cost more than it would

14 have cost had we not hedged if you were buying purely at

15 the spot price, yes.

16 Q. And that happens when the prices are going

17 down, and when the prices go up, you achieve savings; is

18 that correct?

19 A. That is correct. In fact, I think 2002

20 through 2005, we had realized savings associated with

21 our hedge program of $926 million. So, yes. And that's

22 what I alluded to in the beginning, is that we realize

23 there are going to be gains and losses on a year-to-year

24 basis associated with hedging, because we are trying to

25 reduce the volatility associated with fuel prices.

205

1 Q. I saw that in your testimony. And the

2 Commission didn't approve the risk management concept

3 until October of 2002, so I presume that you had been

4 hedging before the Commission approval came in place; is

5 that correct?

6 A. We had been engaged in very minimal type

7 hedging prior to the order coming out. The order

8 addressed expanded hedging programs, and that is surely

9 what we did after the order came out. But prior to the

10 order, we did engage in some minimal type hedging.

11 Q. Did you have long-term fixed contracts for the

12 purchase of gas and coal prior to 2002?

13 A. For natural gas, I believe actually in 2002,

14 one of the first years I can recall, we did have a small

15 contract in place for fixed price natural gas, physical

16 side. Of course, we began utilizing natural gas storage

17 as a hedging tool back in late 2000 on an interruptible

18 basis, so we had been utilizing that, but again, very

19 minimal prior to that. Now, coal, I believe we do have

20 fixed price contracts, but that would be subject to

21 check.

22 Q. At the present time, what is the maximum

23 length of a hedging contract, a futures contract you

24 enter into for natural gas?

25 A. Right now, currently, for natural gas, we are

206

1 really up to one year out. We have not gone farther

2 than that in our hedging program. We have stayed within

3 the next recovery period.

4 Q. Enron would go 10 and 12 years out. Would you

5 deem that to be imprudent?

6 MR. BUTLER: I object to that as calling for a

7 legal conclusion.

8 BY MR. McWHIRTER:

9 Q. Is there a point beyond which you would think

10 that the hedging would be imprudent for a number of

11 years out into the future?

12 MR. BUTLER: Same objection.

13 MR. McWHIRTER: Would you state the rationale

14 for your objection, please?

15 MR. BUTLER: You seem to be asking him to

16 reach a legal conclusion about imprudence.

17 MR. McWHIRTER: What I'm -- his testimony is

18 to demonstrate the success of the program, and it's

19 also, I would presume, to determine whether the risk

20 management -- what the parameters of prudence are. And

21 he's the expert, and I would think that he would be

22 aware of what the parameters of prudence are in hedging,

23 so I don't understand what your objection would be.

24 MR. BUTLER: The objection is to the legal

25 conclusion regarding prudence. I would not object to a

207

1 question about reasonableness, although I'm not sure

2 what the reasonableness of Enron's program has to do

3 with FPL's practices.

4 MR. McWHIRTER: All right. I'll scratch

5 Enron.

6 BY MR. McWHIRTER:

7 Q. But I would presume -- you are obviously the

8 expert in the field, far more so than probably anyone in

9 the room.

10 Well, I take that back. There are probably a

11 lot more experts. But irrespective of that, do you know

12 what is reasonable and what you would deem to be

13 unreasonable with respect to time periods beyond which

14 you should not hedge?

15 A. I would say that from that perspective, I'm

16 not sure what would be unreasonable to hedge. I think

17 that's all dependent upon the company, what they're

18 hedging for, what their risk profile may or may not be.

19 So it's difficult to make a conclusion that hedging 20

20 years out in advance is imprudent. I don't know that to

21 be the case.

22 I know for Florida Power & Light that as of

23 right now, we do hedge up to the next recovery period,

24 which is a year out, and that's what we feel comfortable

25 with at this point in time.

208

1 Q. And would it be fair to say that if over a

2 period of time, some years you have losses and some

3 years you have gains, but over a period of time, if your

4 hedging program tracks the spot market that it has been

5 a success?

6 A. I'm not sure I follow. If --

7 Q. Well, how do you define success in your

8 hedging program?

9 A. Well, I think success really is in a reduction

10 of volatility and greater price certainty. I think

11 there's really no better way to show that than really to

12 look at marked-to-market values of our hedge positions

13 at any given point in time. And I can go back to 2005,

14 December of 2005, and look at -- the marked-to-market

15 position of our '06 portfolio was at $1.2 billion

16 positive.

17 So, you know, we talk about fuel prices having

18 come down throughout 2006, but there was a time shortly

19 prior to that year where without our hedges, we were

20 looking at $1.2 billion more in cost, and now that has

21 obviously come down, as evidenced by the number I gave

22 you of the $262 million realized.

23 But the success of the program is in sticking

24 to what we agree upon, you know, is the intent of the

25 program, which is to reduce volatility. And the only

209

1 way you can do that is to develop what you believe your

2 percentages should be, how much you should hedge, what

3 types of instrument, and stick with it, and not

4 speculate on where the market is going and adjust your

5 plan according to that, because I think in the long run,

6 that produces more volatility, because I have no better

7 idea of where the market is going than you may or

8 anybody else.

9 So, you know, the success of the program is in

10 the volatility reduction. And I think we have seen that

11 since its inception. You look at the savings that we

12 generated up through 2005, and now obviously we're on

13 the other side of that. And that is what we have said

14 all along can happen with hedging. If you are going to

15 hedge to reduce volatility, you will have gains, and you

16 will have losses. There is no doubt about it. That is

17 the only way that you can deliver greater price

18 certainty. And so our program has done that since its

19 inception.

20 Q. Your program is not designed to improve

21 reliability, is it?

22 A. Reliability? From a reliability standpoint,

23 the hedging that is done with option premiums, with

24 swaps, with fixed price components, because

25 predominantly it is financial, no. I will say that the

210

1 physical aspect of our program, and that revolves around

2 our natural gas storage, yes, that is designed to

3 increase reliability.

4 Q. We're going to get to that later. But

5 principally, hedging avoids volatility?

6 A. Yes, sir.

7 Q. And it does not -- from your viewpoint, it

8 would be speculative if you're trying to save money on

9 gas, because that way you would be trying to track --

10 speculatively track the market; is that correct?

11 A. That is correct.

12 Q. Wouldn't it be fair to say that if you bought

13 gas at $5 above the NYMEX for the next year that you

14 could guarantee that you're going to have no volatility?

15 Isn't that correct?

16 A. I'm not sure you could guarantee that you

17 would have no volatility if you bought it right now at

18 $5 above the NYMEX. I'm not sure why you would do that.

19 You know, we buy our gas at the NYMEX, so to speak, when

20 we are putting hedge transactions on, so we are not, you

21 know, above or below, so to speak. We are buying at the

22 NYMEX.

23 Q. Okay. So when the NYMEX falls, do you try to

24 balance out your account so that you more closely

25 approach what the NYMEX is for, say, six months down the

211

1 road?

2 A. Well, depending on how far along into the

3 hedge program or into -- how close you are to your

4 ultimate goal, your ultimate hedge percentage, to the

5 extent the market falls and you are continuing to hedge,

6 yes, your average hedge price will come down.

7 But to the extent that we have met our goal,

8 so to speak, or our percentage goal for hedging, do we

9 unwind positions because the market has come down? No,

10 we do not do that. We stick with the positions that we

11 have.

12 Q. But you're going to buy a greater percentage,

13 so you buy more MM/Btu at a lower price, so that would

14 tend to levelize your cost.

15 A. It would tend to average down our weighted

16 average cost of hedges, yes.

17 Q. Ms. Dubin has projected that your fuel costs

18 for the year 2007 will be $6.1 billion, so the fuel

19 factor will be set on the basis of $6.1 billion. In

20 order to have a mid-course correction under the

21 Commission's procedure, as I understand it, your fuel

22 costs would have to exceed your estimate by some

23 $600 million.

24 Is there anything that you see on the horizon

25 that would lead you to believe there's a possibility

212

1 that gas prices will go up -- which is what? Fifty

2 percent of your consumption of gas?

3 A. Uh-huh.

4 Q. That it will go up so much as to increase your

5 overall fuel costs more than $600 million?

6 A. I think right now the level of uncertainty

7 really would make me answer "I don't know." And I think

8 that was a lot of the discussion prior to refiling and

9 trying to determine was the current market and the drop

10 in fuel prices, was it going to be a good indicator of

11 what ultimately fuel prices would end up to be in 2007.

12 And as of right now, we have not gone through

13 the winter period. We don't know what winter weather is

14 going to bring. We have not been through next year's

15 hurricane season. We don't know what that will bring.

16 We don't know what will occur in the Middle East from a

17 geopolitical stability type driver of fuel prices. So

18 it's very difficult to predict.

19 Sitting here right now, the information is

20 great. We are at all-time record levels of natural gas

21 storage. There's a lot of reports out that winter

22 weather is going to be fairly mild again, which is one

23 of the drivers that started the decline in prices in

24 2006. So there's a lot of positives out there.

25 But to sit here and tell you that it could not

213

1 change the other way wouldn't be prudent on my part,

2 because I don't know. There is still a lot of

3 uncertainty. There's a lot of unknowns that could

4 change this market tomorrow. And given the amount of

5 natural gas that Florida Power & Light burns and the

6 amount of heavy fuel oil that it burns, it can change

7 very quickly. Dollars can mount up when you talk about

8 10 percent of 6.1 billion.

9 And I'll go back to our marked-to-market

10 positions, as I described before, where in early

11 December we were at $1.2 billion positive. By January,

12 after the weather was somewhat mild for that 30-day

13 period, we were down to 700 million. So we swung

14 $520 million in a 30-day period, and that was on the

15 downside. That can happen on the upside, and it has.

16 So there is no level of certainty there. But

17 at this time, the information that is in the market,

18 it's reasonable, and we'll just really have to wait and

19 see, but it can change.

20 Q. The price was gone down $520 million, but you

21 only reduced your fuel factor or your fuel cost estimate

22 by $300 million; is that correct?

23 A. Actually, what I'm describing was for the '06

24 period. For '07 -- and I don't recall the numbers off

25 the top of my head, but you would be correct in what

214

1 you're saying. Given the fact that there are hedge

2 positions on now, we are done, our hedging for 2007.

3 Yes, you cannot -- you will not experience the full

4 decline in the spot market, so to speak, or in the

5 forward price market to the extent that you have hedges

6 in place that are locking in a price that is higher than

7 that.

8 Now, as I said before, there are ways to

9 mitigate that, and that may be to use more call options,

10 but there's a cost associated with that, cost premiums,

11 and that costs the customer money. However, it allows

12 you to take advantage of a downturn in the market when

13 those options would technically expire worthless. But

14 you're buying fuel at a lower spot market cost or a

15 lower prior to the month cost. So -- I've lost my train

16 of thought. I apologize.

17 Q. Well, that's all right. Final question.

18 A. I was going somewhere with that.

19 Q. Well, it sounded very good before it went.

20 But anyway, final question. Irrespective of

21 whether you hedge or totally ignore hedging and follow

22 the spot market for your natural gas prices, it has no

23 adverse impact on Florida Power & Light, because the

24 costs are fully guaranteed by the Commission's

25 procedures with respect to fuel cost recovery; is that

215

1 correct?

2 MR. BUTLER: I'll object to the form of the

3 question, and in particular object to the

4 characterization that the cost is guaranteed.

5 MR. McWHIRTER: I'm going to restate the form

6 of the question.

7 BY MR. McWHIRTER:

8 Q. Mr. Yupp, when your fuel costs are not fully

9 recovered, under Florida Public Service Commission

10 procedures, does that cost go to the shareholders of

11 company to pick up, or is it recovered through your

12 true-up procedures from customers?

13 A. When we do not recover fully what our fuel

14 costs are in a certain recovery period?

15 Q. Yes, sir.

16 A. That is a cost that goes to the customers,

17 with the caveat that as long as those cost were

18 prudently incurred.

19 Q. And in addition to recovery of your fuel

20 costs, you also recover interest on that from the

21 customers; is that correct?

22 A. Yes, and likewise, the other way if we've

23 overrecovered, give interest back.

24 Q. And when the company hedges its fuel

25 purchases, the costs, the premium costs and the gains

216

1 and losses on hedging, 100 percent of that cost is

2 passed through to the customers through your fuel cost,

3 is that correct, your fuel cost recovery clause?

4 A. If they are deemed to have occurred prudently,

5 yes.

6 Q. Can you tell me a circumstance under which the

7 company would be responsible without the opportunity to

8 recover its fuel costs from customers, presuming that

9 the purchase was prudent and the hedge was prudent?

10 A. No. Not as long as we were prudent in the

11 actions we took, no, I cannot think of one.

12 Q. So in summary then, would it be fair to say

13 that hedging is to avoid -- primarily to avoid

14 volatility, it does not, should not be designed to

15 speculatively safe on fuel costs, and hedging with

16 financial institutions does not improve reliability?

17 A. That's true.

18 Q. Does the company receive any rewards or

19 incentives under the Commission's hedging program as it

20 is presently structured?

21 A. No, we do not.

22 MR. McWHIRTER: I tender the witness.

23 CHAIRMAN EDGAR: Are there any other parties

24 with cross for this witness?

25 Seeing none, are there questions from staff?

217

1 MS. BENNETT: Yes, Madam Chair, I have a few.

2 CROSS-EXAMINATION

3 BY MS. BENNETT:

4 Q. Regarding the Southeast Supply Header pipeline

5 project -- and if you want to take a minute to turn

6 to -- I think it's on page 33 and 32 of your testimony.

7 MR. BUTLER: I'm sorry. Which one?

8 MS. BENNETT: The September 1st projection

9 testimony.

10 MR. BUTLER: Thank you.

11 THE WITNESS: Okay. I'm there.

12 BY MS. BENNETT:

13 Q. FPL's participation in the SESH pipeline will

14 result in additional gas transportation costs to get gas

15 to the Mobile Bay area. That's what you said in your

16 testimony; is that correct?

17 A. That is correct.

18 Q. And on page 32 of your testimony, you refer to

19 the current premium of Mobile Bay prices above the

20 NYMEX. I realize this can be somewhat difficult to

21 quantify, but in general, what is that premium?

22 A. Generally, if we were to just look at on

23 average, 2006 to date, the premium for FGT Zone 3

24 deliveries above the Henry Hub was on average around 32

25 cents in MM/Btu.

218

1 Q. Is there a range of prices?

2 A. There can be a pretty significant range. I've

3 seen everything from being flat to -- during hurricane

4 periods, as we experienced in 2005 with Hurricane

5 Katrina in particular, that basis was as high -- I

6 believe it was, subject to check, over $5 premium for

7 FGT Zone 3 above the Henry Hub.

8 Q. The normal range I think you've testified to

9 before was approximately 20 cents to up to 85 cents; is

10 that correct? Is that the normal range?

11 A. Yes. I think we've seen that typically on a

12 day-to-day basis, barring any severe weather events or

13 events such as that.

14 Q. You believe that lower price gas from the

15 Perryville area and more supply into the Mobile area

16 allows for the possibility of savings that will offset

17 the additional transportation costs; is that correct?

18 A. Yes, that is correct. We believe that we will

19 be able to procure natural gas in the Perryville area at

20 such price to offset the firm transportation that we are

21 proposing to acquire on the Southeast Supply Header

22 pipeline.

23 Q. As an alternative to the Southeast Supply

24 Header project, isn't it true that you considered

25 liquefied natural gas?

219

1 A. Yes, we did evaluate liquefied natural gas

2 proposals as far back as 2004 when issued an RFP for

3 liquefied natural gas. And also, as we answered in our

4 interrogatory responses, we did look at four particular

5 LNG facilities that were proposed in the Gulf Coast as

6 alternatives, as well as two additional pipelines

7 similar to Southeast Supply Header. We did also

8 evaluate those as alternatives.

9 Q. And you began evaluating those in 2004; is

10 that correct?

11 A. LNG was being evaluated in 2004 as a potential

12 supply alternative. The Southeast Supply Header

13 pipeline as well as the two alternate pipelines and the

14 LNG facilities on the Gulf Coast I believe were sometime

15 early in 2006 or late 2005, but that would be subject to

16 check. I'm not 100 percent sure on that.

17 MS. BENNETT: I have no further questions of

18 this witness.

19 CHAIRMAN EDGAR: Mr. Butler?

20 MR. BUTLER: Thank you. Just a couple of

21 redirect questions, Madam Chair.

22 REDIRECT EXAMINATION

23 BY MR. BUTLER:

24 Q. Mr. Yupp, does FPL file with the Commission

25 each year a report on its hedging program and the

220

1 results of the program?

2 A. Yes, we do.

3 Q. Would you just briefly explain what is

4 contained in that report?

5 A. In the yearly filing that we make, generally

6 around April 1st, we provide a recap of all our hedging

7 activity for the prior period or prior year. We list

8 out of all the instrument types that we used and the

9 volumes associated with those instrument types for

10 natural gas, heavy fuel oil, and for power, as well as

11 the dollar values for savings or -- gains or losses

12 associated with each instrument. We do that by month,

13 and then, obviously, it's rolled up into an aggregate

14 total for the year.

15 Q. Thank you. You discussed this at some length

16 with Mr. McWhirter, but would you just summarize

17 succinctly what you consider the goal of FPL's hedging

18 program to be?

19 A. Yes. The goal of our hedging program since

20 day one has been to reduce volatility, to not engage in

21 speculative trading, which I believe would increase

22 volatility. Trying to outguess the market, I don't

23 think any of us can do that. There are sometimes

24 drivers of the market that are hard to understand. The

25 market moves a certain direction when maybe the

221

1 information says it really shouldn't move in that

2 direction.

3 So again, we are going to execute a well

4 disciplined, independently controlled program. We're

5 going to continue to try to reduce volatility for our

6 customers.

7 You know, the one thing that we do every year

8 is, we do look at market trends. We can take them into

9 account. We can modify the types of hedges that we use,

10 the types of instruments we use to mitigate some of the

11 potential movement in the market. But in a nutshell, we

12 are trying to reduce volatility, is the bottom line.

13 Q. Given that goal, would you consider FPL's

14 hedging program to have been successful to date?

15 A. Yes, I would.

16 MR. BUTLER: Thank you. That's all the

17 redirect that I have.

18 CHAIRMAN EDGAR: Do we need to do exhibits?

19 MR. BUTLER: Yes. No Commission questions, I

20 assume. Yes, I would move Exhibits 11, 12, 13, and 14.

21 CHAIRMAN EDGAR: Those exhibits will be moved

22 into the record.

23 (Florida Power & Light Company Exhibits Number

24 11, 12, 13, and 14 were admitted into evidence.)

25 CHAIRMAN EDGAR: Commissioners, were there

222

1 questions that I didn't see? No.

2 Okay. Then the witness is excused. Thank you

3 very much.

4 MR. BUTLER: Thank you.

5 CHAIRMAN EDGAR: Let's take about seven

6 minutes. I need to stretch. We will go on a very short

7 break.

8 (Short recess.)

9 CHAIRMAN EDGAR: We are going to begin again.

10 Mr. Butler.

11 MR. BUTLER: Madam Chairman, I believe that

12 FPL's next two witnesses, first of all, Mr. Gwinn was

13 previously excused, and that Ms. Sonnelitter's testimony

14 concerning the subjects that would come up at this

15 point, which are just the targets and results for GPIF,

16 have been stipulated.

17 And if that is correct, we would move the

18 admission of their testimony. And Ms. Sonnelitter has

19 exhibits that I will also refer to for admission into

20 the record. It would be her Exhibit PS-1 and her

21 Exhibit PS-3, which are 15 and 17.

22 CHAIRMAN EDGAR: Okay. Ms. Bennett, don't we

23 need to move -- although Witness Gwinn was excused,

24 don't we need to move that testimony and --

25 MS. BENNETT: Yes.

223

1 CHAIRMAN EDGAR: -- exhibits into the record

2 as well?

3 MR. BUTLER: He has no exhibits, so I just

4 moved his testimony. But he does not have any exhibits.

5 CHAIRMAN EDGAR: Okay. So the prefiled

6 testimony of Witness Gwinn is entered into the record as

7 though read, and the prefiled testimony and exhibits of

8 Witness Sonnelitter will also be entered into the

9 record.

10 (Florida Power and Light Company Exhibits

11 Number 15 and 17 were admitted into evidence.)

12 MR. BUTLER: And just for clarification, I

13 should probably note that's her April 3, 2006, and

14 September 1, 2006, testimony. She does have August 22,

15 2006 testimony that we'll get to when we do the GPIF

16 policy issues later.

17 CHAIRMAN EDGAR: So she will be called and

18 available for questions later in the proceeding.

19 MR. BUTLER: That's right.

20 CHAIRMAN EDGAR: Okay.

21 MR. BUTLER: Thank you.

22 CHAIRMAN EDGAR: Thank you.

23

24

25

256

1 CHAIRMAN EDGAR: Mr. Horton.

2 MR. HORTON: Yes, ma'am. Florida Public

3 Utilities would call Mr. George Bachman. And, Madam

4 Chairman, all four of the FPUC witnesses have been

5 sworn.

6 Thereupon,

7 GEORGE BACHMAN

8 was called as a witness on behalf of Florida Public

9 Utilities Company, and, having been first duly sworn,

10 was examined and testified as follows:

11 DIRECT EXAMINATION

12 BY MR. HORTON:

13 Q. Would you state your name and address for the

14 record, please, sir.

15 A. Yes. George Bachman, 401 South Dixie Highway,

16 West Palm Beach, Florida.

17 Q. And by whom are you employed, Mr. Bachman?

18 A. Florida Public Utilities Company.

19 Q. Have you prepared and prefiled direct

20 testimony in this docket consisting of three pages?

21 A. Yes, I have.

22 Q. Do you have any changes or corrections to make

23 to that testimony?

24 A. No.

25 Q. If I asked you the questions contained in that

257

1 testimony today, would your answers be the same?

2 A. Yes, they would.

3 MR. HORTON: Madam Chairman, I would request

4 that Mr. Bachman's testimony be inserted in the record

5 as though read.

6 CHAIRMAN EDGAR: The prefiled testimony will

7 be inserted into the record as though read.

8 BY MR. HORTON:

9 Q. And you had no exhibits, did you, Mr. Bachman?

10 A. No, I did not.

11 Q. Do you have a brief summary to present at this

12 time?

13 A. Sure. Florida Public Utilities has two

14 divisions that we serve electricity. We distribute

15 electricity in northern Florida, our Northwest Division,

16 which serves Marianna, and Northeast Division, which

17 serves Fernandina Beach. We have purchased power

18 contracts to purchase the electricity, two of the

19 contracts, one for each of those divisions. Those

20 contracts expire at the end of 2007.

21 Back in 2005, anticipating these contracts and

22 their expiration, we went out and decided to hire a

23 consultant. We did that for two reasons: (1) The

24 contract would be expiring; and (2) because of the

25 complex nature of fuel contracts, we needed an expert in

258

1 that field.

2 We hired Christensen & Associates -- Robert

3 Camfield is here today -- to do the analysis for us.

4 Also, they handled the RFP process. They handled the

5 negotiations and came up with final recommendations for

6 awarding the contracts.

7 We have concluded this process for our

8 Northeast Division, which serves again Fernandina Beach.

9 We have entered into an amended contract with JEA to

10 provide that power beginning in 2007. That new pricing

11 has been put into our fuel projections.

12 That concludes my summary.

13

14

15

16

17

18

19

20

21

22

23

24

25

262

1 MR. HORTON: Mr. Bachman is available.

2 CHAIRMAN EDGAR: Ms. Christensen.

3 MS. CHRISTENSEN: No questions.

4 MR. McWHIRTER: No questions.

5 CAPTAIN WILLIAMS: No questions.

6 CHAIRMAN EDGAR: Are there questions on cross

7 for this witness by any other parties? No?

8 Are there questions from staff?

9 MS. BENNETT: No questions of this witness.

10 CHAIRMAN EDGAR: Commissioners, any questions?

11 All right.

12 MR. HORTON: May Mr. Bachman be excused?

13 CHAIRMAN EDGAR: He may.

14 MR. HORTON: I don't think I have any redirect

15 for him.

16 CHAIRMAN EDGAR: Thank you, Mr. Bachman.

17 THE WITNESS: Thank you.

18 MR. HORTON: We would call Mr. Robert

19 Camfield.

20 Thereupon,

21 ROBERT CAMFIELD

22 was called as a witness on behalf of Florida Public

23 Utilities Company and, having been first duly sworn, was

24 examined and testified as follows:

25

263

1 DIRECT EXAMINATION

2 BY MR. HORTON:

3 Q. Would you state your name and address for the

4 record, please, sir.

5 A. My name is Robert J. Camfield, and my business

6 address is 4610 University Avenue, Madison, Wisconsin.

7 Q. And by whom are you employed, Mr. Camfield?

8 A. Christensen Associates Energy Consulting.

9 Q. Mr. Camfield, did you prepare and prefile in

10 this docket direct testimony consisting of 27 pages?

11 A. I did.

12 Q. Do you have any changes or corrections to make

13 to that testimony?

14 A. There are no changes or corrections.

15 Q. If I asked you the questions contained in that

16 testimony today, would your answers be the same?

17 A. They would.

18 MR. HORTON: Madam Chairman, may I have

19 Mr. Camfield's direct testimony inserted in the record

20 as though read?

21 CHAIRMAN EDGAR: The prefiled direct testimony

22 will be entered into the record as though read.

23 BY MR. HORTON:

24 Q. Mr. Camfield, you had no exhibits attached to

25 your testimony either, did you?

264

1 A. There are no exhibits.

2 Q. Do you have a summary of your testimony at

3 this time?

4 A. Yes. As Mr. Bachman mentioned, Florida Public

5 Utilities has current separate contracts for power

6 supply for its Northeast and Northwest Divisions. Those

7 contracts terminate in 2007, year-end, and thus the

8 company decided, with our advice, to enter into an open

9 solicitation for power supply and to initiate that power

10 supply solicitation in midyear 2005.

11 We did that in the form of an April request

12 for power supply proposal, an RFP, and we solicited

13 letters of intent from a number of parties that provide

14 power supply in the Southeast region. We obtained

15 letters of intent to provide offers for power supply

16 offer packages from nine entities, and we took offer

17 packages, submitted offer packages in May of 2005 from

18 seven entities, potential power suppliers.

19 So that essentially kicked off our 2005 RFP

20 process that subsequently gave rise to an evaluation of

21 the offers that we had in front of us for both the

22 Northeast and Northwest Divisions.

23 We then conducted a quasi-auction for what we

24 refer to as qualified offer packages for qualified

25 bidders, and through a three-round auction came up with

265

1 a set of offers that were really overall, considering

2 all factors, fairly close and competitive.

3 We thus conducted a second iteration of

4 evaluation of the final offer packages and provided

5 recommendations on those packages to Florida Public

6 Utilities using known criteria for evaluation. And the

7 company then decided on the winning bidder to its RFP

8 solicitation process. It was Southern Company. More

9 specifically, Southern Power Company was the winning

10 bidder to the Northeast Division, and Gulf Power Company

11 was the winning bidder to the Northwest.

12 The difficulty, of course, with bidders to the

13 north of FPU is that the transmission interface can get

14 congestion that's problematic along the Georgia-Florida

15 interface. And as a result of that, we in the process

16 of the solicitation, knowing that a number of the

17 bidders were from the north, engaged in two different

18 power transport -- should I say transmission supply

19 strategies, one of which was the consideration of a

20 separate radial line to link Fernandina Beach, the

21 Northeast Division, to the Southeast Reliability

22 Council, known as the SERC.

23 So the effect of that potentially would have

24 been, should it succeed as a transmission strategy, was

25 to remove the Northeast Division from the FRCC region,

266

1 the benefit being that the benchmark wholesale prices to

2 the north of Florida, the Florida peninsula, because of

3 the transmission constraint, are lower substantially

4 from that of the FRCC. So that long-term strategy was

5 part of the alternative power supply arrangements that

6 were being considered at the time.

7 Because of the asset concentration, the

8 investment requirements for the radial line, the

9 uncertainty associated with the completion of the line

10 in the time frame required to get the permits and build

11 and construct the line, plus reliability issues with a

12 dual circuit line -- we simultaneously knew these

13 things, of course, ahead of time and proceeded to

14 consider an alternative transmission strategy, which was

15 to obtain access to the transmission network,

16 specifically the interface itself, through the OATT of

17 JEA.

18 The constraints are well known on the

19 Georgia-Florida interface and, of course, because of the

20 constraints and so forth, firm service was not available

21 to us, and thus we were essentially precluded from

22 completing the power supply arrangement for the winning

23 bidder, Southern Power Company, and thus have proceeded

24 to negotiate a power supply contract with JEA, who was

25 the incumbent supplier for the Northeast Division.

267

1 And it is that power supply contract, as

2 Mr. Bachman mentioned, that is determining the prices

3 for the 2007 time frame. Those prices are, as I state

4 in my testimony, overall, for both generation and

5 transmission services, at $45 per megawatt-hour under

6 the amended contract, the current contract with its

7 amendments.

8 The commercial terms give rise to increases in

9 the prices for power supply over the 2008 and 2009 time

10 frame, with the prices for 2008 at $59 per

11 megawatt-hour, including transmission, and at $73, which

12 is the full price level at cost of service, cost of

13 service based prices for power supply, given JEA's

14 embedded cost for generation services. And that price

15 beginning in 2009 forward is at $73, but will escalate

16 over the future years of the contract, which run through

17 the year 2017.

18 And that concludes my summary.

19

20

21

22

23

24

25

295

1 MR. HORTON: Mr. Camfield is available.

2 CHAIRMAN EDGAR: Are there questions on cross?

3 MS. CHRISTENSEN: No questions.

4 MR. McWHIRTER: No questions.

5 CAPTAIN WILLIAMS: No questions.

6 CHAIRMAN EDGAR: Okay. Are there questions on

7 cross for this witness from any of the other parties?

8 Seeing none, are there questions from staff?

9 MS. BENNETT: Yes, Madam Chair.

10 CROSS-EXAMINATION

11 BY MS. BENNETT:

12 Q. I think I understood you to say that for the

13 Northeast Division, FPUC could not contract with the

14 winner of the 2005 RFP process because of transmission

15 constraints; is that correct?

16 A. That's correct.

17 Q. For the Northeast Division, isn't it true that

18 the existing power supply contract with JEA expires at

19 the end of 2007?

20 A. That's correct.

21 Q. And would you agree that FPUC is proposing to

22 forgo the last year of its power supply arrangements

23 with JEA so that FPUC can obtain the proposed long-term

24 contract with JEA?

25 A. That's correct.

296

1 Q. In your direct testimony on page 23, you talk

2 about the Northeast Division and the new power supply

3 contract with JEA which result in higher prices for

4 customers in 2007, 2008, and 2009, and I believe I heard

5 you testify to those numbers. They will be increasing

6 each year; is that correct?

7 A. That's correct.

8 Q. On page 23 again of your testimony, on line 9,

9 you note the average offer price of $79.94 based on the

10 RFP process. Is that a correct number?

11 A. That's correct.

12 Q. Is it your belief that the new contract with

13 JEA has favorable price terms compared to the request

14 for proposal process that you previously described?

15 A. That is my expectation. Over the longer term

16 forward period, as well as the current time frame here

17 that we're talking about, 2007 and 2009, I feel that

18 these embedded cost based contract prices with JEA are

19 very favorable with regards to both the offer prices as

20 received in response to the 2005 RFP of Florida Public

21 Utilities, as well as projections of long-term wholesale

22 prices in their region.

23 MS. BENNETT: Madam Chair, I have no further

24 questions of this witness.

25 CHAIRMAN EDGAR: Commissioner Arriaga.

297

1 COMMISSIONER ARRIAGA: Sir, you mentioned the

2 Georgia-Florida interface constraints as one of the

3 reasons for going the route of contracting with JEA at

4 higher rates. Could you explain that a little bit,

5 because there have been times here that we have spoken

6 about these interface constraints. I think the

7 Department of Energy has pointed out some issues

8 regarding that interface constraint.

9 What moved you to accept this contract versus

10 considering a potential solution, or is there no

11 solution to that Georgia-Florida interface constraint?

12 THE WITNESS: Well, as I discussed in the

13 testimony, Commissioner, the interface constraints are

14 well known. And the two issues that Florida Public

15 Utilities faces with regards to transmission is, number

16 one, can it obtain access rights for transmission under

17 JEA's open access transmission tariff, which is modeled

18 after the FERC OATT first established in 1996. And that

19 tariff has two main transmission service types, network

20 service and point-to-point service.

21 For the most part, wholesale power

22 transactions over the interface to the peninsula of

23 Florida service providers are point-to-point service

24 arrangements utilizing the tariff and priced at the

25 posted tariff prices of the JEA OATT.

298

1 The other transmission service type is known

2 as network integration transmission service, and that

3 service is for incumbent service providers like Florida

4 Public Utilities that would utilize multiple generation

5 resources within the control area, in this case, JEA.

6 So the issue as far as transmission access is

7 concerned is whether or not FPU would be entitled to

8 access rights of the interface facilities because it is

9 an incumbent service provider, an incumbent customer of

10 FPU, where under the rollover provision, and thus giving

11 you access rights, you can redesignate the generation

12 resources to the new supplier, in this case, Southern

13 Power Company.

14 Southern Power resources, of course, are to

15 the north of JEA, and thus we would need to have that

16 access right, those transmission access rights in order

17 to obtain the power over the interface. And that's the

18 key interpretation issue as far as access, transmission

19 access rights are concerned.

20 And as I discussed, the other transmission

21 option available to FPU, at least potentially, would be

22 the construction of a radial line in both options. The

23 use of the existing transmission interface, should we

24 be -- should I say should we obtain transmission access

25 rights, as well as the radial line, were considered in

299

1 the -- or should I say along with and parallel to the

2 2005 RFP process.

3 My apologies for that long-winded answer.

4 COMMISSIONER ARRIAGA: No, that's fine.

5 I think I am as concerned as you are about the

6 transmission interface.

7 THE WITNESS: Oh, yes.

8 COMMISSIONER ARRIAGA: I've been talking to

9 staff about it, and --

10 THE WITNESS: It's a serious issue.

11 COMMISSIONER ARRIAGA: It is a serious issue.

12 Your contract, I understand, with JEA is for

13 three years. I'm sorry, ten years, 2017. But I see

14 right here for the next three years only. What is it

15 going to be in 2017?

16 THE WITNESS: The prices, should I say the

17 commercial terms of the current contract amendment for

18 the period 2008 and 2009 and all forward years will be

19 determined by cost of service allocation. And

20 specifically with the amendment are cost of service

21 principles that define the methodology in general terms

22 under which JEA will conduct a cost of service

23 allocation study and determine essentially the share of

24 total embedded cost of generation resources of JEA that

25 would be allocated to FPU as a wholesale customer of

300

1 JEA. And that cost of service process will determine

2 the nonfuel-related costs for the -- of the commercial

3 terms of the contract amendment for all forward years,

4 2008 forward.

5 COMMISSIONER ARRIAGA: Just one last

6 statement. I guess what I'm concerned about, and

7 probably you are too, and the company is also, that you

8 will find yourselves eventually with one supplier and

9 being slowly choked. Do you have any other alternative

10 to continuously having to negotiate a contract that is

11 going to be higher and higher and higher as the years go

12 by because you have no other source of supply?

13 THE WITNESS: Well, the company -- if the

14 contract prices, the resulting contract prices, the

15 commercial terms themselves of the amendment were not

16 favorable, that would be a major concern. In fact, the

17 contract amendment allowed Florida Public Utilities

18 Company to elect one of two options.

19 The shorter term option was an incremental

20 cost based option. It was a set of commercial terms

21 known as Option A, where those terms were determined on

22 the basis of incremental costs, the internal incremental

23 costs of JEA to provide resources. Of course, I've had

24 a chance to look in detail at the underlying costs of

25 both Option A and Option B, the longer term embedded

301

1 cost option selected by FPU. I've had a chance to

2 review the financial forecasts of JEA and the fuel costs

3 and the way it does things.

4 And so taken as a whole, Commissioner -- and,

5 frankly, I share your concerns. But taken as a whole, I

6 think it's quite favorable, and I don't feel that there

7 is great danger for a price escalation that would put

8 FPU in a position of having, or paying, should we say,

9 noncompetitive wholesale prices for generation and

10 transmission services.

11 COMMISSIONER ARRIAGA: All right. Thank you

12 very much.

13 THE WITNESS: Yes, sir.

14 CHAIRMAN EDGAR: Mr. Horton.

15 MR. HORTON: No redirect. May Mr. Camfield be

16 excused?

17 COMMISSIONER CARTER: The witness may be

18 excused. Thank you.

19 THE WITNESS: Thank you.

20 MR. HORTON: And I would call Mr. Cutshaw.

21 Thereupon,

22 MARK CUTSHAW

23 was called as a witness on behalf of Florida Public

24 Utilities Company and, having been first duly sworn, was

25 examined and testified as follows:

302

1 DIRECT EXAMINATION

2 BY MR. HORTON:

3 Q. Would you state your name and address for the

4 record, please, sir.

5 A. My name is Mark Cutshaw, Florida Public

6 Utilities Company. My address is 911 South Eighth

7 Street, Fernandina Beach, Florida, 32034.

8 Q. What is your position with Florida Public

9 Utilities?

10 A. I am the general manager for the Northeast

11 Florida Division.

12 Q. Did you prepare and prefile in this docket

13 direct testimony consisting of three pages?

14 A. Yes, I did.

15 Q. Do you have any changes or corrections to make

16 to that testimony?

17 A. No, I don't.

18 Q. If I were to ask you the questions contained

19 in that testimony today, would your answers be the same?

20 A. Yes, they would.

21 MR. HORTON: Madam Chairman, I would ask that

22 his prefiled direct testimony be inserted into the

23 record as though read.

24 CHAIRMAN EDGAR: The prefiled testimony of the

25 witness will be inserted into the record as though read.

303

1 BY MR. HORTON:

2 Q. And you had no exhibits to your testimony

3 either, did you?

4 A. No, I didn't.

5 Q. Do you have a summary to present at this time?

6 A. Yes, I do. During 2005, we realized that the

7 impact on our customers beginning in what we had thought

8 at the time to be 2008 would be significant. We began

9 to explore different alternatives to try to mitigate

10 this significant rate increase that would occur at that

11 time. We looked at alternatives.

12 We filed formal proceedings that, although

13 they were not approved, did allow public hearings to

14 occur. It did bring information to this venue to go out

15 to the public. We had media releases in the communities

16 during 2005 that informed them things would change going

17 forward. They were used to very, very favorable

18 pricing, and that would come to an end.

19 As I mentioned, those alternatives were not

20 approved. However, in 2006, as we moved through the

21 process of getting a new power contract, we also

22 retained a firm that worked with us to provide

23 additional communications to our customers to inform

24 them that, yes, prices would increase. We also provided

25 them with information on conservation techniques that

304

1 they could use when the prices went up to help avoid

2 significant cost to them.

3 So we have been continuing. We will continue

4 after the results of this docket are closed in informing

5 our customers exactly what to expect going forward and

6 will do whatever we can to assist them in making

7 preparations to do so.

8 That concludes my summary.

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

308

1 MR. HORTON: Mr. Cutshaw is available.

2 CHAIRMAN EDGAR: Ms. Christensen.

3 MS. CHRISTENSEN: No questions.

4 MR. McWHIRTER: No questions.

5 CAPTAIN WILLIAMS: No questions.

6 CHAIRMAN EDGAR: Okay. Questions on cross

7 from any other parties for this witness?

8 Seeing none, questions from staff?

9 MS. BENNETT: Yes, Madam Chair.

10 CROSS-EXAMINATION

11 BY MS. BENNETT:

12 Q. Mr. Cutshaw, I understand you've begun to

13 provide notice to your customers about the increased

14 rates. If the Commission were to approved your

15 company's proposed cost recovery related to the power

16 supply contract with JEA, can you describe briefly what

17 the company will do to notify your customers of the

18 Northeast Division of the proposed increases for 2008

19 and 2009?

20 A. Given that the prices would go into effect

21 beginning in January, we have already begun informing

22 the customers that prices will increase. We have -- we

23 were kind of in the middle of, "Do we tell them what we

24 think will occur, or do we tell them nothing until it's

25 approved?" We made the choice to go ahead and tell the

309

1 customers that we anticipate approval.

2 We've talked to large commercial customers.

3 We've talked to the industrial customers. We've sent

4 bill inserts to residential customers. We've provided

5 conversation tips to all the customers. So we have

6 informed them that we anticipate, based on approval

7 today, that their prices will increase, and that will

8 continue up through January.

9 MS. BENNETT: That answers the questions I

10 have for this witness. Thank you.

11 CHAIRMAN EDGAR: Commissioners, any questions?

12 No?

13 Mr. Horton.

14 MR. HORTON: No questions. May Mr. Cutshaw be

15 excused?

16 CHAIRMAN EDGAR: The witness may be excused.

17 Thank you.

18 THE WITNESS: Thank you.

19 MR. HORTON: And I would call Cheryl Martin.

20 Thereupon,

21 CHERYL MARTIN

22 was called as a witness on behalf of Florida Public

23 Utilities Company and, having been first duly sworn, was

24 examined and testified as follows:

25

310

1 DIRECT EXAMINATION

2 BY MR. HORTON:

3 Q. Would you state your name and address for the

4 record, please, ma'am?

5 A. Cheryl Martin, 401 South Dixie Highway, West

6 Palm Beach, Florida.

7 Q. And by whom are you employed?

8 A. Florida Public Utilities Company.

9 Q. And did you cause to be prepared and prefiled

10 in this docket direct testimony dated February 26th

11 consisting of two pages?

12 A. Yes.

13 Q. August 8th, consisting of two pages, and

14 revised direct testimony on October 26th consisting of

15 four pages?

16 A. Yes.

17 Q. Do you have any changes or corrections to make

18 to that testimony?

19 A. No, I do not.

20 Q. If I were to ask you the questions contained

21 in that testimony today, would your answers be the same?

22 A. Yes, they would.

23 MR. HORTON: I would ask that Ms. Martin's

24 direct testimony dated February 26th, August 8th, and

25 the revised direct dated October 26th be inserted into

311

1 the record as though read.

2 CHAIRMAN EDGAR: The prefiled testimony will

3 be inserted into the record as though read.

4 BY MR. HORTON:

5 Q. Ms. Martin, did you also prepare exhibits that

6 have been identified CMM-1, CMM-2, and CMM-3, which are

7 identified as Exhibits 20, 21, and 22?

8 A. Yes, I did.

9 Q. And did you submit a revised a schedule CMM-3

10 on October 26th with respect to Fernandina Beach?

11 A. Yes, I did.

12 Q. And those were prepared by you or under your

13 supervision?

14 A. Yes, they were.

15 Q. Do you have a summary of your testimony to

16 present at this time?

17 A. Yes. My testimony and the related exhibits

18 provide the computations for the proposed fuel factors

19 for 2007 for both our Northeast and Northwest Divisions.

20 I've also included testimony and related exhibits

21 relating to the true-up contained in those same 2007

22 projections. I summarized the various fuel factors by

23 rate class, the true-up amounts, and the impacts to the

24 residential customers that are using 1,000 kWh. I've

25 also incorporated the impact of the new fuel contract in

312

1 our Northeast Division into our 2007 fuel projections.

2 I revised the original projections filed in September

3 2006 for the Northeast Division on October 27, 2006, and

4 included the related testimony and exhibits for those

5 revisions.

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

321

1 MR. HORTON: Ms. Martin is available.

2 CHAIRMAN EDGAR: Questions on cross?

3 MS. CHRISTENSEN: No questions.

4 MR. McWHIRTER: No questions.

5 CAPTAIN WILLIAMS: No questions.

6 CHAIRMAN EDGAR: Questions on cross for this

7 witness from any other party?

8 Seeing none, questions from staff?

9 MS. BENNETT: Staff has no question for this

10 witness.

11 CHAIRMAN EDGAR: Commissioners? No?

12 Mr. Horton.

13 MR. HORTON: I would move entry of Exhibits

14 20, 21, and 22.

15 CHAIRMAN EDGAR: The exhibits will be moved

16 into the record.

17 (Florida Public Utilities Exhibits Number 20,

18 21, and 22 were admitted into evidence.)

19 MR. HORTON: Thank you. And may Ms. Martin be

20 excused?

21 CHAIRMAN EDGAR: The witness may be excused.

22 Thank you.

23 MR. HORTON: That concludes Florida Public

24 Utilities.

25 CHAIRMAN EDGAR: Mr. Badders.

322

1 MR. BADDERS: We would call Rusty Ball to the

2 stand.

3 Thereupon,

4 H. R. BALL

5 was called as a witness on behalf of Gulf Power Company

6 and, having been first duly sworn, was examined and

7 testified as follows:

8 DIRECT EXAMINATION

9 BY MR. BADDERS:

10 Q. Mr. Ball, were you present this morning when

11 the witnesses were sworn in?

12 A. Yes, I was.

13 Q. Could you please state your name and your

14 business address for the record?

15 A. My name is Herbert R. Ball. My business

16 address is One Energy Place, Pensacola, Florida, 32520.

17 Q. By whom are you employed, and in what

18 position?

19 A. I'm employed by Southern Company Services,

20 Inc. as fuel manager for Gulf Power Company.

21 Q. Are you the same H. R. Ball who prefiled

22 direct testimony on March 1, 2006, consisting of ten

23 pages, August 8, 2006, consisting of 11 pages, and on

24 September 1, 2006, consisting of ten pages?

25 A. Yes, I am.

323

1 Q. Do you have any changes or corrections to that

2 testimony?

3 A. Yes, I do have one change. On page 5, line 7

4 of my March 1st testimony, I need to change the word

5 "increase" to "decrease."

6 Q. With that correction, if I were to ask you the

7 same questions today, to your answers be the same?

8 A. Yes, they would.

9 MR. BADDERS: We would ask that the prefiled

10 direct testimony of Mr. Ball be inserted into the record

11 as though read.

12 CHAIRMAN EDGAR: Excuse me. The prefiled

13 testimony of this witness will be inserted into the

14 record as though read with the correction as noted by

15 the witness.

16 MR. BADDERS: Thank you.

17 BY MR. BADDERS:

18 Q. Mr. Ball, did you also have two exhibits

19 attached to that testimony?

20 A. That's correct.

21 Q. And those are labeled HRB-1. And we need to

22 make a correction to the second one. It is incorrectly

23 listed as HRB-1, but it's HRB-2, and that would be to

24 the September 1 testimony. And with that correction, do

25 you have any other changes or corrections to your

324

1 exhibits?

2 A. No, I did not.

3 MR. BADDERS: We ask that that exhibit be

4 identified. I believe they were preidentified as 23 and

5 24.

6 COMMISSIONER CARTER: So noted.

7 MR. BADDERS: Thank you.

8 BY MR. BADDERS:

9 Q. Mr. Ball, please summarize your testimony.

10 A. Yes. My responsibility at Gulf Power is to

11 manage the fuel program in a manner that assures a

12 reliable supply of fuel at the lowest practical cost to

13 Gulf's customers over time.

14 Gulf's primary source of fuel for generation

15 of electricity is coal. Gulf purchases coal using a

16 combination of short- and long-term supply agreements.

17 The short-term agreements are priced at market, and the

18 price is fixed over the term of the agreement.

19 Long-term agreements are priced using a competitive bid

20 process, and the price-certain nature of these

21 agreements provide a physical cost hedge to protect

22 against large increases in market prices.

23 Natural gas is a secondary fuel for Gulf, but

24 represents a significant cost or a significant

25 percentage of the cost of the fuel program to Gulf's

325

1 customers. Gulf's strategy for the procurement of gas

2 is to contract for supply using long-term agreements at

3 market price. The goal is to provide gas suppliers

4 market price to assure supply during normal supply

5 periods and to rely on natural gas storage to provide

6 supply during supply disruptions.

7 Gas hedges -- Gulf hedges the price of a

8 percentage of these of purchase agreements using

9 financial hedges. These financial hedges accomplish the

10 same objective as the physical price hedge of Gulf's

11 long-term coal supply agreements by protecting against

12 large increases in the market price of natural gas and

13 providing price certainty for a portion of Gulf's gas

14 purchases.

15 We believe that these coordinated coal and gas

16 procurement strategies prudently deliver the primary

17 objectives of Gulf's fuel program.

18 And that concludes my summary.

19

20

21

22

23

24

25

357

1 MR. BADDERS: Thank you. This witness is

2 available for cross-examination.

3 CHAIRMAN EDGAR: Thank you. Questions on

4 cross?

5 MS. CHRISTENSEN: Yes.

6 CROSS-EXAMINATION

7 BY MS. CHRISTENSEN:

8 Q. Good afternoon, Mr. Ball. I have a few

9 questions about Gulf's gas storage. Would you agree

10 that Gulf obtained its natural gas storage for Plant

11 Crist approximately September 1st, 1997?

12 A. Yes, I agree with that.

13 Q. And would you also agree that the carrying

14 costs applicable to any fuel kept in storage should be

15 recovered through base rates, not through the fuel

16 clause?

17 A. That's correct. Natural gas storage costs or

18 carrying costs were included in base rates in our last

19 rate proceeding.

20 Q. Okay. And your last rate proceeding had a

21 test year of May 31st, 2003, and that would have been in

22 Docket 010949E; is that correct?

23 A. That's correct.

24 Q. Okay. And is it correct to say that your

25 inventory balance of natural gas storage was included in

358

1 your working capital calculation in your last rate case?

2 A. That's correct.

3 Q. And that was for the projected test year,

4 which ended May 31st, 2003; correct?

5 A. Correct.

6 MS. CHRISTENSEN: I have no further questions.

7 CHAIRMAN EDGAR: Mr. McWhirter.

8 MR. McWHIRTER: Yes, ma'am.

9 CROSS-EXAMINATION

10 BY MR. McWHIRTER:

11 Q. Mr. Ball, you were deposed on October 23rd,

12 and you were asked if you had not hedged in 2006, your

13 fuel costs would be lower, but you didn't specify how

14 much lower they would have been for this year. Can you

15 give us -- can you tell us what your hedging losses will

16 be in 2006?

17 A. Our current estimate of hedging losses in 2006

18 amount to $17.4 million.

19 Q. Your total fuel costs are $454.7 million for

20 2007?

21 A. Yes.

22 Q. Have you projected whether you're going to

23 have gains or losses in 2007?

24 A. Based on the current market price of gas, we

25 have projected that we are going to pay to the bank

359

1 approximately $2 million in 2007 for the settlement of

2 our financial hedges.

3 Q. You are a subsidiary of the Southern Company,

4 and Southern Company is deeply involved in the futures

5 market, as I understand it. Is that correct?

6 A. Well, I guess, yes, I would agree with that to

7 some degree. Yes, specifically in natural gas hedging,

8 which I'm familiar with, Southern Company -- all of the

9 operating companies within Southern Company do

10 financially hedge natural gas purchases; that's correct.

11 Q. Do you deal with and pay commissions to the

12 Southern Company for hedging transactions?

13 A. No. Gulf Power does not pay any commissions

14 to Southern Company for hedging gas transaction.

15 Q. In your opinion, would it be appropriate to

16 pay commissions on hedging to affiliated companies?

17 A. It's -- I guess since we don't pay any

18 commission and we don't have a program that involves

19 commissions, we don't anticipate ever having that

20 situation come up.

21 Q. You indicated that you had long-term coal

22 contracts, coal purchase contracts. Do you consider

23 those long-term contracts to be hedges, and do you

24 include them in your hedging program?

25 A. We consider long-term contracts that are for a

360

1 specific quantity of fuel at specific prices to be

2 physical hedges of fuel prices; that's correct. And I

3 guess in a way, that is a part of our fuel procurement

4 strategy, and it is a part of our filing that we make

5 with the Commission that details our procurement

6 strategy, yes.

7 Q. And how long have you been engaged in

8 long-term purchases and your coal supply contracts?

9 A. Southern Company as a whole has been involved

10 in the long-term coal procurement process for many

11 years. I would hesitate to say how far back, but

12 certainly longer than I've been associated with Southern

13 Company.

14 Q. So although those are classified as physical

15 hedges currently, they've been in -- that operation was

16 in existence long before the Commission's order

17 approving hedging programs in 2002; is that correct?

18 A. That is correct. But I would state that

19 Southern Company, and particularly Gulf Power Company,

20 is not a significant and has not been a significant

21 utilizer of natural gas for fuel. We are primarily a

22 coal-fired utility, and Gulf Power is and in the past

23 was much more of a coal-fired utility.

24 Q. When you engage in hedging transactions, what

25 percentage are financial hedges as opposed to physical

361

1 hedges for gas?

2 A. For gas, we are 100 percent financially

3 hedged, at least all of our hedging is financially

4 hedged. We do not enter into physical price hedges on

5 our gas agreements.

6 Q. Your gas storage gives you additional

7 reliability. In your opinion, do you obtain additional

8 reliability for your gas supply through financial

9 hedging?

10 A. There's no connection between gas storage and

11 financial hedging. We employ gas storage primarily for

12 reliability of supply and for operational reasons, to

13 balance gas flows in and out of the pipelines.

14 Q. Did you hear Mr. Yupp's testimony? Were you

15 in the room when he talked about hedging?

16 A. Yes, I was here.

17 Q. Do you agree with his concept that it is not

18 the purpose of hedging to save fuel costs or to lower

19 fuel costs or to speculate, but rather only to avoid

20 volatility?

21 A. Gulf Power certainly is involved in the gas

22 hedging process in an attempt to reduce volatility of

23 fuel prices. Also, primarily, it's to protect the

24 customers against large increases in fuel prices.

25 As far as the speculative nature of the

362

1 program, we have certain percentages that we will hedge

2 up to to prevent us from becoming more of a speculative

3 program, so we would never hedge more than 100 percent

4 of our forecasted burn in any case.

5 Q. That's good.

6 A. Doing more than you're -- hedging more than

7 you burn would certainly put you into a speculative

8 position.

9 Q. Do you have limits on your hedging now that is

10 not confidential?

11 A. We don't consider our hedging limits

12 confidential. We have a specific strategy that we

13 employ. We update that strategy each month. Typically

14 our strategy is that we will hedge between 40 and

15 60 percent of our forecasted gas burn for the next year,

16 and we hedge up to 42 months in advance.

17 Q. As you get closer to the burn date, do you

18 hedge a larger percentage and then a smaller percentage

19 as you're further away? Is that the way the program

20 works?

21 A. No, not necessarily. Our hedge program is

22 typically built around watching the market and making

23 strategic decisions about when to hedge and when not to

24 hedge. We don't set time limits on when we need to

25 hedge. We don't try to hedge more as we approach the

363

1 burn date.

2 Actually, what we're looking for is -- we're

3 looking at the marketplace, and if we see that there's a

4 dip in gas prices that provide an opportunity to hedge,

5 we'll take that opportunity and do so at that time.

6 So in some cases, we will have our gas hedges

7 in place several years before the actual gas burn

8 occurs. In other cases, we may see an opportunity to

9 hedge prices in a few months before the gas burn occurs,

10 and if we think that that is an advantageous time to

11 hedge prices, we'll enter the market and do so.

12 Q. Does your 2007 fuel cost recovery application

13 include any O&M costs that relate to your hedging

14 program, O&M as opposed to commissions and --

15 A. Yes, we do.

16 Q. And what is that amount of money?

17 A. I believe for the '07 forecast, it's

18 approximately $98,000.

19 Q. The stipulation we entered into back in

20 October -- or August of 2002 that was approved by the

21 Commission in October limited the time period with which

22 you could recover these costs to end at December 31,

23 2006. Were you aware of that?

24 MR. BADDERS: I would like to make an

25 objection. He's reading from an order that the witness

364

1 does not have in front of him. If he would like to make

2 that available to the witness, I think that would be

3 more appropriate.

4 CHAIRMAN EDGAR: Mr. McWhirter?

5 MR. McWHIRTER: I will do that, yes. All I

6 have to do is find it.

7 BY MR. McWHIRTER:

8 Q. This is my solitary copy of Commission Order

9 021484 that I hand you to refresh your recollection.

10 The operative paragraph is number 4 in the stipulation

11 that I've yellow marked. Would you read that into the

12 record?

13 A. May I read the entire paragraph, sir?

14 Q. Well, the yellow marked part.

15 A. Well, there's -- okay. I'll read that, but if

16 you don't mind, I will read a little bit further to

17 clarify this.

18 Q. Please do.

19 A. Thank you.

20 Q. Read whatever makes you comfortable to

21 accurately portray what the stipulation says.

22 A. Thank you, sir. "Each investor-owned eletric

23 utility may recover through the fuel and purchased power

24 cost recovery clause prudently incurred incremental

25 operating and maintenance expenses incurred for the

365

1 purpose of initiating and/or maintaining a new or

2 expanded nonspeculative financial and/or physical

3 hedging program designed to mitigate fuel and purchased

4 power price volatility for its retail customers each

5 year until December 31, 2006, or the time of the

6 utility's next rate proceeding, whichever comes first."

7 Q. All right. Did you have a rate proceeding in

8 which the Commission approved incremental hedging as a

9 fuel cost recovery as --

10 A. It's my understanding --

11 Q. -- opposed to base rates?

12 A. I'm sorry. It's my understanding that Gulf's

13 rate proceeding occurred prior to the hedging order, so

14 our next rate proceeding will be at a later date.

15 Q. Now, in fairness to you, Gulf did not sign

16 that stipulation, and you'll see from the order that

17 Gulf came along later. And I'm not sure I understand

18 the circumstances of that. Do you know the basis upon

19 which you recover your O&M costs through the fuel clause

20 for 2007?

21 A. It's my understanding that we have the

22 opportunity to recover our O&M costs up until the point

23 that we have our next rate proceeding.

24 Q. Is that what you think that order says?

25 A. That's my interpretation, yes, sir.

366

1 Q. All right, sir. Thank you very much for that.

2 How do you determine internally when a hedging

3 program is, quote, successful?

4 A. The overall objective of the hedging program,

5 of course, is to save the customer money. We should not

6 involve ourselves in any hedging program that is not to

7 the benefit of the customer. So over the long term --

8 that's not just looking at one year or one month, but

9 over a long period of time, the customer should see

10 tangible benefits from a hedging program.

11 Now, we believe that the hedging program is a

12 benefit, because over the time period that we've been

13 involved in the hedging program, we have shown tangible

14 benefits in dollars and cents to our customers. This

15 program is out there to protect the customer against

16 large increases in gas prices.

17 Who knows what the future may hold? But

18 certainly if you look at past history, you will see that

19 we've had many occasions where gas prices have increased

20 dramatically, and there's certainly no assurance that

21 that will not happen in the future. The gas hedging

22 program is out there to protect the customers against

23 those occurrences. If we determine that the gas hedging

24 program does not accomplish that feat, then certainly

25 the gas hedging program should not be continued.

367

1 Q. The gas hedging programming entails

2 commissions and other fees. What fees do you pay for

3 the privilege of engaging in hedging?

4 A. Gulf Power Company does not pay any

5 commissions or fees associated with its gas hedging

6 program.

7 Q. Do you deal over the counter, or do you deal

8 with a commodity exchange?

9 A. We deal strictly with financial institutions

10 that are creditworthy based on analyses that are made by

11 our risk management group. Out hedges are primarily and

12 for the most part financial swaps.

13 Q. Do you pay option premiums?

14 A. No, we do not.

15 Q. What do you mean by a financial swap?

16 A. A financial swap is where you take a position

17 on a firm quantity of gas at a firm price, and then at

18 the settlement date of that agreement, you settle either

19 against a last-day NYMEX price, Henry Hub basis, or you

20 can swap that for a gas daily price and settle those

21 agreements each day as you -- in this case, in our case,

22 we consider -- as we're burning the gas, we may elect to

23 swap this month-end price to a gas daily settlement

24 price and settle as we burn the gas.

25 Q. And when you deal with a financial

368

1 institution, you don't pay any fee or premium to the

2 institution other than specified price for the commodity

3 you're purchasing?

4 A. In the transactions that we're involved in,

5 that is true.

6 Q. Can you name some of your counterparties, or

7 is that privileged information?

8 A. No, I wouldn't consider it privileged

9 information, but organizations like the Bank of America,

10 Mitsui Corporation, to name a few. If you would like a

11 more extensive list, I can get that for you.

12 MR. McWHIRTER: That's all right. I have no

13 further questions and tender the witness.

14 CHAIRMAN EDGAR: Thank you. Does any other

15 party have questions on cross for this witness?

16 MR. BUTLER: Madam Chairman, I have a couple

17 of questions, if I may.

18 CROSS-EXAMINATION

19 BY MR. BUTLER:

20 Q. Good afternoon, Mr. Ball. My name is John

21 Butler with Florida Power & Light Company. I just have

22 a couple of questions for you.

23 There was a reference early in the examination

24 of you this afternoon to MFRs that were prepared for a

25 test year that ended in -- well, I think it ended May

369

1 31, 2003, is that right, your most recent rate

2 proceeding?

3 A. That is correct.

4 Q. So it was a one-year period ending May 31,

5 2003?

6 A. That's correct.

7 Q. Okay. And to state the obvious, therefore, it

8 began in May of 2002; correct?

9 A. That is correct.

10 Q. Okay. Do you know when the MFRs were prepared

11 or that set of MFRs were prepared for the test year

12 running from May 2002 to May 2003?

13 A. No, I do not.

14 Q. But it would have been sometime before the

15 May 2002 point; correct?

16 A. I would assume so. I was not in this role at

17 that time.

18 Q. Okay. In any event, a date before May 2002

19 would have been before the Commission had entered its

20 hedging order approving the hedging resolution; is that

21 correct?

22 A. That's correct.

23 MR. BUTLER: Thank you. That's all that I

24 have.

25 CHAIRMAN EDGAR: Any other party with

370

1 questions on cross?

2 Seeing none, questions from staff?

3 MS. BENNETT: Staff has no questions.

4 Commissioners.

5 CHAIRMAN EDGAR: Mr. Badders.

6 MR. BADDERS: No redirect. And we would like

7 to move Exhibits 23 and 24.

8 CHAIRMAN EDGAR: The exhibits will be moved

9 into the record.

10 (Gulf Power Company Exhibits Number 23 and 24

11 were admitted into evidence.)

12 CHAIRMAN EDGAR: And the witness may be

13 excused.

14 MR. BADDERS: The next two witnesses I believe

15 may be subject to being stipulated. We can take them

16 one at a time if you prefer.

17 CHAIRMAN EDGAR: Ms. Bennett?

18 MS. BENNETT: I believe that Ms. Martin, all

19 of the issues for Gulf have been stipulated, and if that

20 is the case and no party objects, then we can stipulate

21 the testimony and exhibits into the record.

22 MS. CHRISTENSEN: No objection.

23 CHAIRMAN EDGAR: Seeing no other objection,

24 okay. Then the prefiled testimony of Ms. Martin will be

25 entered into the record as though read.

371

1 MR. BADDERS: And Exhibits 25 through 27.

2 CHAIRMAN EDGAR: And Exhibits 25 through 27.

3 (Gulf Power Company Exhibits Number 25, 26,

4 and 27 were admitted into evidence.)

5

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

383

1 MR. BADDERS: The next witness is Witness

2 Noack. I believe the same is also true with regard to

3 her projections and target filing testimony, which would

4 include both Exhibits 27 and 28.

5 CHAIRMAN EDGAR: Is there any objection to

6 entering the prefiled testimony of Witness Noack into

7 the record?

8 MS. CHRISTENSEN: No objection.

9 MR. McWHIRTER: No objection.

10 CHAIRMAN EDGAR: Then the prefiled testimony

11 of Ms. Noack and her -- excuse me, of Witness Noack and

12 Exhibits 27 and 28 will be entered into the record.

13 MS. BENNETT: Can I clarify just a moment,

14 Madam Chair?

15 CHAIRMAN EDGAR: You may, Ms. Bennett.

16 MS. BENNETT: First, Ms. Noack will appear

17 later on the dead band issue, so we will be entering

18 just the testimony for April and --

19 MR. BADDERS: That is correct. We would enter

20 just the April and September testimony. The August

21 testimony would still be outstanding.

22 CHAIRMAN EDGAR: Okay. For clarification, the

23 April and September prefiled testimony is entered into

24 the record, and the August testimony we will take up

25 later in this proceeding.

384

1 MR. BADDERS: Right. And I do believe I

2 misspoke on the exhibits. I believe for Witness Martin

3 it's 25 through 27, and for Noack, it's 28 and 29.

4 CHAIRMAN EDGAR: So noted.

5 (Gulf Power Company Exhibits Number 28 and 29

6 were admitted into evidence.)

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

398

1 MS. HELTON: Madam Chairman, this is --

2 CHAIRMAN EDGAR: Ms. Helton, yes.

3 MS. HELTON: Just for purposes of

4 clarification of the record -- and I apologize. This is

5 probably something I should have checked out before

6 mentioning it, but do we need to mention on the record

7 that Ms. Martin is adopting the prefiled testimony of

8 Terry A. Davis, or is that already made clear enough?

9 MR. BADDERS: I believe we made that clear at

10 the prehearing, and I believe it appears in the

11 prehearing order, but at the Commission's pleasure, we

12 can do that.

13 MR. HORTON: I just think stating it on the

14 record is probably good enough.

15 CHAIRMAN EDGAR: Okay. Then once again, for

16 the record, Witness Martin has also adopted the prefiled

17 testimony and exhibits of Witness Davis.

18

19

20

21

22

23

24

25

405

1 MR. BADDERS: Thank you. I believe that

2 concludes the Gulf witnesses for this section.

3 CHAIRMAN EDGAR: That is my understanding.

4 And it looks like that's a good time for us to break, so

5 we will do that here in a few moments.

6 Are there any questions, comments, concerns

7 that we should address before we go on break to resume

8 again in the morning?

9 Okay. Seeing none, then we are on break until

10 9:30 tomorrow morning, and we will begin with Witness

11 Portuondo.

12 (Proceedings adjourned at 5:08 p.m.)

13

14

15

16

17

18

19

20

21

22

23

24

25

406

1 CERTIFICATE OF REPORTER

2

3 STATE OF FLORIDA:

4 COUNTY OF LEON:

5 I, MARY ALLEN NEEL, Registered Professional

6 Reporter, do hereby certify that the foregoing

7 proceedings were taken before me at the time and place

8 therein designated; that my shorthand notes were

9 thereafter translated under my supervision; and the

10 foregoing pages numbered 188 through 405 are a true and

11 correct record of the aforesaid proceedings.

12 I FURTHER CERTIFY that I am not a relative,

13 employee, attorney or counsel of any of the parties, nor

14 relative or employee of such attorney or counsel, or

15 financially interested in the foregoing action.

16 DATED THIS 7th day of November, 2006.

17

18

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

19 MARY ALLEN NEEL, RPR, FPR

2894-A Remington Green Lane

20 Tallahassee, Florida 32308

(850) 878-2221

21

22

23

24

25