BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 150001-EI

FUEL AND PURCHASED POWER COST
RECOVERY CLAUSE WITH
GENERATING PERFORMANCE
INCENTIVE FACTOR.
_________________________________/

VOLUME 4

(Pages 581 through 810)

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JULIE I. BROWN
COMMISSIONER JIMMY PATRONIS

DATE: Tuesday November 3, 2015

TIME: Commenced at 9:30 a.m.
Concluded at 12:10 p.m.

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

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
35 through 39			713
50 through 52			784
117			713
118			784
125	Excerpt of FPUC 2014 FERC Form 1	602	638

P R O C E E D I N G S

CHAIRMAN GRAHAM: Good morning, everyone. Glad to see you all have made it here safely this morning. And not to delay anymore, we'll start off with our very first witness. Ms. Keating.

MS. KEATING: Good morning, Mr. Chairman, Commissioners. FPUC calls Mr. Mark Cutshaw.

Whereupon,

MARK CUTSHAW

was called as a witness on behalf of FPUC and, having first been duly sworn, testified as follows:

EXAMINATION

BY MS. KEATING:

Q Good morning, Mr. Cutshaw.

A Good morning.

Q If you would, please introduce yourself to the Commission and state your business address.

A My name is Mark Cutshaw. My business address is 1750 South 14th Street, Fernandina Beach, Florida 32034.

Q And you were in the room yesterday, were you not, and have already been sworn in?

A Yes.

Q Okay. Please go ahead, if you would, and tell us who your employer is and what your position is with the company.

A I'm employed by Florida Public Utilities Company, and I'm the Director of Business Development and Generation.

Q And did you prefile testimony in this proceeding on September 1st?

A Yes, I did.

Q Do you have any corrections to that prefiled testimony?

A Yes, I do. There was one typo on page 7, line 5 of my testimony, and the word "of" was left out of the sentence. And it should read, "The FPUC 138 kV transmission line is a dual circuit single pole line which includes several miles of transmission line in a relatively inaccessible marshy area."

Q And with that correction, if I asked you all the questions that are in your prefiled testimony, would your responses still all be the same?

A Yes, they would.

MS. KEATING: Chairman Graham, with that correction, we'd ask that Mr. Cutshaw's prefiled testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Cutshaw's prefiled direct testimony into the record as though read.

MS. KEATING: Thank you.

BY MS. KEATING:

Q Mr. Cutshaw, you did not have any prefiled exhibits; correct?

A That's correct.

ERRATA

P. Mark Cutshaw – PROJECTION TESTIMONY/FILED SEPTEMBER 1, 2015

Page 7, Line 5: Insert the word "of" between the words "miles" and "transmission, so that the sentence reads:

The FPUC 138 KV transmission line is a dual circuit, single pole line which includes several miles **of** transmission line in relatively inaccessible marshy areas.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2016 Projection Testimony of
Mark Cutshaw
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is P. Mark Cutshaw, 1750 S. 14th Street, Suite 200, Fernandina Beach, Florida 32034.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. I joined FPUC in May 1991 as Division Manager in the Marianna (Northwest Florida) Division. During my employment with Florida Public Utilities, I have worked extensively in both the Northeast and Northwest Divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During 2015, I moved into my current role as Director, Business Development and Generation.

Q. Have you previously testified in this Docket?

A. Yes, on numerous occasions.

I. Efforts to Reduce Fuel Costs

Q. Has the Company investigated means to reduce costs for its customers in its consolidated electric divisions?

A. Yes. The Company has aggressively sought opportunities to engage its current base load providers for both electric divisions in discussions for an arrangement that would be more beneficial for the FPUC customers. Since 2007, when purchased power rates began to increase significantly from both providers, FPUC has been very assertive in challenging each cost determination performed by JEA and Southern Company that resulted in an increase to the purchased power rate. These very focused and steady efforts have resulted in the mitigation of increases in purchased power costs for FPUC and its customers. In January 2011, the Company was also successful in completing an Amendment to the Gulf Power contract, reducing costs to customers in its NW division.

These same focused and steady efforts are continuing today and have resulted in a reduced rate of increase to FPUC and its customers.

The Company has also investigated other opportunities to reduce purchases power costs, including the possibility of contractual relationships with other wholesale power suppliers. As a result of this ongoing investigation into new opportunities, relationships were developed with other suppliers, informal studies of generation and transmission capacity arrangements were reviewed, and contract possibilities were discussed. Although realization of these opportunities is not possible until the expiration of the existing power purchase contracts, the information gathered has provided FPUC with invaluable market knowledge and material that will further assist with our further discussions. Among the notable information gleaned, the Company has determined that an FPL interconnect in its Northeast Division will provide future opportunities to save customers on fuel costs and increase the reliability in the Northeast Division.

Q. Has the Company availed itself of other opportunities to produce fuel cost savings?

A. Yes. For instance, the Northeast Division provides service to two paper mills on Amelia Island that have significant on site generation capabilities. These relationships have created further opportunities for some limited purchased power for FPUC. FPUC has entered into arrangements with these alternative power providers that have thus far proven very advantageous. FPUC is continuing to look at these and all other avenues for reducing purchased power costs.

Q. What arrangements with "alternative power providers" do you refer to?

A. The first very successful arrangement that I am referring to is the renewable energy contract with Rayonier Performance Fibers, LLC, which was entered into in early 2012 and approved by the Commission in Docket No. 120058-EQ. Through a cooperative effort, FPUC and Rayonier were able to develop a purchased power agreement that allows Rayonier to produce renewable energy and sell that energy to FPUC at a cost below that of the current wholesale power provided while still being beneficial to Rayonier. Not only did this increase the amount of renewable energy in the area, it provides lower cost energy that is passed directly through to FPUC customers in the form of reduced power cost.

Secondly, FPUC has completed the development of a partnership with Eight Flags Energy, LLC to provide lower cost reliable energy which will provide benefits to the FPUC customers. The Commission has reviewed this agreement and approved it in Docket No. 140185-EQ on December 30, 2014. The combined heat and power facility owned by Eight Flags Energy, LLC, a subsidiary of Chesapeake Utilities Corporation (Chesapeake), will work directly with FPUC to provide additional energy to FPUC. This new 20 megawatt generation facility will provide significant cost savings to FPUC customers in both divisions.

Q. How have these new arrangements proven beneficial to the Company?

A. This new project it is expected to be in service by the second quarter of 2016 and is expected to produce further significant benefits for the Company and all of its electric customers.

All in all, this contract will secure added service reliability for the Northeast Division while providing customers in both divisions significant fuel and purchased power cost savings. It will do so all while producing a lower environmental profile than would be associated with locating traditional generation on the island or with FPUC's purchased power options. Not only will this new contract provide customers with lower cost energy, this contract will also provide FPUC with negotiating leverage that is not currently available. This added leverage is expected to enhance our ability to negotiate beneficial contracts with large wholesale power providers for future agreements and should help with even further energy.

II. New Efforts Targeting Additional Savings

Q. Can you provide additional information on the transmission interconnect project?

A. Yes. This is a significant project for FPUC, one that the Company has embarked upon specifically because we anticipate it will directly improve our ability to negotiate increased savings for our customers in our next power purchase agreements. Historically, FPUC's ability to secure competitive wholesale power quotations has been hindered by the limitation on the transmission interconnections providing power to FPUC's Northeast Division. At present, FPUC's 138 KV transmission is directly connected to the JEA 138 KV transmission network. The FPUC 138 KV transmission line is a dual circuit, single pole line which includes several miles **of** transmission line in relatively inaccessible marshy areas. This transmission line serves as the only off-island power supply to Amelia Island. In order to resolve this issue for upcoming wholesale power proposals, FPUC is pursuing an interconnection with the Florida Power & Light's (FPL) transmission system, which is located in very close proximity to the existing FPUC transmission system. Not only will this additional interconnection provide for more competitive wholesale power options, this will provide much needed redundancy to the power supply on Amelia Island and have a positive impact on the overall system reliability.

Q. What type of construction will be necessary to accomplish the interconnection with FPL?

A. The FPUC owned 138 KV transmission line is located approximately 750 feet (0.14 miles) from the FPL substation and runs in the existing right of way along with the FPL 230 KV transmission line. The construction necessary will include expansion of the existing FPL substation in which the necessary transmission and system protection equipment will be placed in order to allow for the interconnection of the FPUC 138 KV transmission line. The FPUC 138 KV transmission will be re-routed to parallel the FPL 230 KV transmission line into the expanded substation. The new system design will provide for improved system reliability on the transmission system and will afford FPUC the opportunity to reach other less expensive generation sources while avoiding additional transmission wheeling cost.

This additional interconnection with FPL will also provide expanded opportunities should it become necessary and/or advantageous to export power from the CHP generating resources on Amelia Island. The ability to have more opportunities and avoid one transmission wheel can provide additional benefits to FPUC customers by maximizing revenues for off system sales.

Q. What is the projected in service date for the interconnection with the FP&L transmission system?

A. The exact date of the interconnection completion has not been determined; but, is expected during the latter half of 2017.

Q. Can you quantify or project the savings to be derived as a result of this new interconnect with FPL?

A. While we cannot specifically define what those savings will be, nor will be able to do so until negotiations for future agreements are complete, we have projected what we anticipate the savings will be, as addressed in the testimony of FPUC's witness Young.

Q. Are there other efforts underway to continue to provide lower cost energy to FPUC customers?

A. Yes. Due to the significant benefits that are provided to the Rayonier and Eight Flags Energy projects, FPUC has continued to identify other projects that provide similar benefits. These projects include additional Combined Heat and Power (CHP) projects, additional transmission line interconnections and photovoltaic projects.

Q. Can you provide additional information on the CHP projects?

A. Yes. Although the projects have not been finalized at this point, there are currently CHP projects in development. It is uncertain whether or not these will be available for service in 2016; but, work is ongoing with regard to the engineering and contractual aspects of the projects. To be clear, these costs are not included in the projections for 2016.

Q. In addition to CHP, is FPUC also considering the feasibility of solar photovoltaic projects?

A. Yes. FPUC has determined that the development of smaller solar photovoltaic systems within the FPUC electric service territory is economically feasible and can provide benefits to the rate payers. Based on this analysis, FPUC is working to acquire the necessary property to construct a small scale (one to five megawatts) PV installation. Not only will this increase the renewable energy available to FPUC, the cost is expected to be less than the current wholesale power cost, which will provide additional benefits to FPUC customers. Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. The output from these systems have not been included in the projections.

Q. Does this conclude your testimony?

A. Yes.

BY MS. KEATING:

Q And did you prepare a summary of your testimony?

A Yes, I did.

Q If you would, please go ahead and provide that.

A Good morning, Commissioners. My name is Mark Cutshaw, and I'm here on behalf of Florida Public Utilities Company. I currently serve as the Director of Business Development and Generation for FPU and submitted prefiled testimony in this proceeding regarding FPU's efforts to reduce fuel costs and new efforts targeting additional savings.

As you're aware, the fuel rates to FPU customers began to increase significantly in 2007. This was based on the changes in our purchased power contracts for power, and we heard loud and clear from our customers that something needed to be done about the increases. In response, FPU began a focused effort to look for means by which the overall purchased power cost could be reduced.

Because we have limited staff resources, we hired several very experienced industry and legal consultants to assist us in our efforts. With their help, the company has evaluated a number of possible solutions that could help reduce the fuel cost for our customers.

The solutions evaluated have included projects developed by the company as well as projects and opportunities brought to us by other entities. Through these efforts, we've been able to produce savings for our customers and plan projects that we believe will bring even more savings upon implementation.

The most significant and most recent example of these efforts was the partnership we just developed with Eight Flags Energy, LLC, which is located just north of Jacksonville on Amelia Island. This partnership will provide low-cost reliable electricity to FPU customers beginning in 2016. Our dynamic approach, as well the constructive regulatory environment in Florida, has allowed this project to occur, assuring reduced costs for FPU's customers in the future.

We've also identified another key project that will produce significant additional savings for our customers. With the help of the team we have assembled, we have pursued an opportunity to interconnect our Northeast Florida Division transmission system with the FPL transmission system. This transmission interconnection will provide access to additional wholesale power sources, and it will provide access to additional sources that will enhance significantly our leverage as we pursue our next purchased power agreement. We also anticipate the new interconnection will provide not only access to lower cost options, but will result in reduced transmission costs. Additionally, this transmission interconnection will provide an increased level of reliability to an area that has been impacted by reliability issues in previous years.

FPU has evaluated the impact of this additional transmission interconnection and determined that this will provide FPU customers with an estimated $2.3 million in savings in future purchased power costs. Additional savings will continue in future years. With the Commission's approval, FPU can proceed with this project so that this valuable interconnection can be placed in service and fully utilized on December 31st, 2017, which is at the end of our existing wholesale power agreement.

While FPU is a small non-generating utility, we're serious about finding new and better ways to produce savings for our customers. As such, we hope the Commission will approve our request in this proceeding, including recovery of costs associated with the FPL interconnect and recovery of fuel-related legal and consulting fees. We hope to continue to benefit our customers by saving them money.

Thank you, Commissioners.

MS. KEATING: With that, Mr. Chairman, Mr. Cutshaw is tendered for cross.

CHAIRMAN GRAHAM: Thank you, Ms. Keating.

OPC.

MS. CHRISTENSEN: Good morning. I have several exhibits that I would request that we pass out.

CHAIRMAN GRAHAM: Okay. We've got somebody who can help you with that.

(Pause.)

Ms. Christensen, we have numbers 125, 126, and 127.

MS. CHRISTENSEN: Well --

CHAIRMAN GRAHAM: I see you already have two of these already, Nos. 90 and 91.

MS. CHRISTENSEN: Correct. They're excerpts from the composite exhibit that were already marked for identification and admitted into the record. Those are for ease of reference during cross-examination. So I only need to have marked for identification the excerpt of the FPUC 2014 FERC Form 1.

CHAIRMAN GRAHAM: We'll give that 125.

(Exhibit 125 marked for identification.)

MS. CHRISTENSEN: Thank you.

CHAIRMAN GRAHAM: You have the floor when you're ready.

MS. CHRISTENSEN: Thank you.

EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Cutshaw.

A Good morning.

Q Okay. You were present in the room yesterday when your colleague Mr. Young was testifying?

A Yes, I was.

Q Okay. And you heard during that cross-examination a description of the activities that were done by the consultants in 2016?

A Yes.

Q And you also heard Mr. Young say that he was not sure what activities occurred in 2015 and he referred them to you. Do you recall that?

A Yes.

Q Okay. To your knowledge, were any of the activities done by the consultants that we discussed yesterday for 2016, were any of those activities significantly different from the activities they performed in 2015?

A Yes. The scope of their activities was basically the same. The focus on the different projects' specific locations were different, but the overall scope of their work was the same.

Q Okay. And I think that's -- so essentially they were working on substantially similar projects to the descriptions that were provided for 2017.

A That's correct.

Q Okay. Now in your direct testimony, pages 9 -- or 6 through 9, you discuss -- I'm sorry. Let me refer you to your projection testimony filed September 1st. You discuss the interconnection project between Florida Power & Light's transmission system and FPUC's transmission system; is that correct?

A Correct.

Q And FPL to the FPUC interconnection when complete will be part of FPUC's transmission system; is that correct?

A That's correct.

Q And the interconnection project is expected to come into service at the end of 2017; is that right?

A That's correct.

Q Now would I be correct in saying that FPUC has a purchased power agreement with Jacksonville Electric Authority?

A Yes.

Q Okay. And is it also correct that that PPA with Jacksonville Electric Authority will not expire until 2017, December 31st?

A That is correct.

Q Okay. And that's -- and let me refer you to Exhibit 91 that I handed out.

A Yes.

Q And you provided that response; correct?

A Yes, I did.

Q Okay. And that's essentially what this response is referring to is the expiration of the JEA PPA; correct?

A That's correct.

Q And it also indicates that FPUC is obligated to take all of its wholesale purchased power from JEA; is that correct?

A That is correct.

Q Okay. And you would agree that under the JEA PPA that FPUC is limited in how it can get any other cheaper wholesale power?

A That's correct.

Q Okay. And would you also agree that beginning January 1st, 2018, is when FPUC can enter into a new PPA contract which it hopes will be for better terms?

A That is correct.

Q Okay. And, finally, you would agree that no fuel savings related to the interconnect can happen in 2016 related to any new interconnection or PPA agreement; correct?

A That is correct. We hope to be able to plan in advance so that beginning in 2018 we'll be able to provide additional savings to our customers. Without the planning it will not occur.

Q Okay. And just to be clear, I'm going to refer you real quick to Exhibit 90 that I passed out. And that was another response that was provided by you; is that correct?

A Yes.

Q Okay. And it does confirm that the existing contract with JEA does not allow taking power from another wholesale power provider; is that correct?

A That's correct.

Q Okay. And you would agree that the fuel savings that were reflected as an attachment in this docket, those fuel savings could not start until after January 1st, 2018.

A That's correct. The 2.3 million that I mentioned in my opening summary will begin in 2018.

Q Okay. Now let me refer you to the exhibit --

do you have a copy of the exhibit that was handed out by staff yesterday, Exhibit 124, which is the June 30th, 2014, surveillance report?

A Yes, I do.

Q Okay. As of June 30th, 2014, Schedule 1 of FPUC's surveillance report reflects an achieved average rate of return of 3.62 percent on an average FPUC adjusted basis; is that correct?

A Yes.

Q Okay. Now can you turn to Schedule 4 that reflects FPUC's capital structure. Let me know when you've reached there.

A Okay.

Q Okay. And would you agree that Schedule 4 reflects FPUC's capital structure?

A This is the first time I've seen this. I would have to look at it a little more closely, but it appears to be.

Q Okay. And isn't it correct that as of June 30th, 2014, the low point of the range for the overall rate of return on an average basis is 5.4 percent? If you look at the top box and you see the headers on there and it says "low point," if you go to the bottom of that box.

A I'm sorry. I was looking at Schedule 3.

Q Okay. Are you on Schedule 4 now?

A This looks more correct now.

Q Yeah, that would help.

A Yes. You are correct.

Q Okay. Great. Thank you.

Now I've handed out an Exhibit No. 125, which is an excerpt of FPUC's 2014 FERC Form 1, and on the last page of that handout, on page 3 there's a note to the financial statements under the heading of "Impairment of Long-Lived Assets." Can you read that first full paragraph on that last page into the record.

A And this is the one immediately under "Impairment of Long-Lived Assets"?

Q Correct. The first full-- or the second one that starts "At December 31st."

A Okay. So the second paragraph?

Q Yes.

A "At December 31st, 2014, we recorded a $1,267,750 pre-tax non-cash impairment loss related to uncertainty around the implementation of a customer billing system. This impairment was part of the 6.5 million impairment loss recorded by Chesapeake and represented all of the capital costs associated with this project allocated to us. The impairment loss is included in the operation expense in the accompanying statement of income. Prior to December 31st, 2014, these costs were included in construction work in progress.

"On May 31st, 2015, Chesapeake entered into a settlement agreement with a system vendor regarding the implementation which provided a cash proceed of 1.5 million and a potential additional proceed of 650,000 if certain conditions and requirements are met by Chesapeake over the following five-year period. We expect to record a gain contingency in 2015 based on the cash proceed allocated to us by Chesapeake.

"We're also considering other options to recover the remaining cost of impairment, including regulatory proceedings. We will establish a regulatory asset if future recovery through rates is probable."

Q Thank you. Now isn't it correct that the asset impairment that's referred to is the ESYS (phonetic) customer billing asset that the company included in construction work in progress in its projected test year in the last rate case?

MS. KEATING: Mr. Chairman, I'm afraid I'm going to have to object. I believe this line of questioning goes far afield of Mr. Cutshaw's testimony.

THE WITNESS: Or my expertise.

CHAIRMAN GRAHAM: Ms. Christensen.

MS. CHRISTENSEN: Well, one, staff brought in the surveillance reports, and we think this is relevant to the surveillance reports that were introduced yesterday as of June 30th, 2015. And a one-time writeoff in 2015 plus some additional cross-examination that I plan to get into needs to be put forward to give a full picture of where they are, base rates versus fuel, because the company has said that they won't have the funds essentially to do this project if they're not given recovery through fuel. And, therefore, I think they've opened up the door to where they are financially related to base rates and what impacts have occurred during the last year that impacted their surveillance report in 2015. All I'm trying to do is give the Commission a more complete picture of where base rates stand as of today.

CHAIRMAN GRAHAM: I understand what you're saying, but this is going beyond what his direct testimony was, and he's already said that this is beyond his expertise.

MS. CHRISTENSEN: Well, if I can --

CHAIRMAN GRAHAM: I mean, he can answer the questions that he can answer. But if those are things that he doesn't know, then we're just going to move on from there.

MS. CHRISTENSEN: Okay. Well, let me explore if he's aware of the one-time writeoff, and then I'll kind of shorten it up and move from there and only explore what he does now.

CHAIRMAN GRAHAM: And I'll also let Ms. Keating, as you drift away from what his direct testimony is, I'll let her throw those objections up there as well.

MS. CHRISTENSEN: Certainly. But I'm afraid -- I think he opened up the door when he went into the legal and consulting fees related to fuel savings and such that were also a little bit -- I think he's testifying across a little bit more than what his testimony was anyway.

CHAIRMAN GRAHAM: Okay. Now repeat that first question.

BY MS. CHRISTENSEN:

Q All I was -- what I'm asking is, and I will phrase it, are you aware that the company took a one-time writeoff for the ESYS (phonetic) project in 2015?

A Yes, vaguely aware.

Q Okay. Do you know the amount that was written off for -- written off in 2015?

A No, I do not.

MS. CHRISTENSEN: Okay. And I will move on from there.

CHAIRMAN GRAHAM: Sure.

BY MS. KEATING:

Q Mr. Cutshaw, if you're aware, do you know -- are you familiar with the surveillance reports?

A Vaguely.

Q Okay. Let me just ask you about the base rate case then. As of June 30th, would you agree that only eight months of the base rate increase were reflected that took effect as of November 1st, 2014?

A Yes.

Q Okay. And if you know, are you aware of -- or let me rephrase it this way. Would you agree that the approximately four months' worth of base rate revenue increase for July, August, September, and October would be approximately a $1 million increase in revenue?

A I would be speculating if I quoted anything.

Q Okay.

A Sorry.

Q That's fine. I just -- if you're not aware, you're not aware, but I appreciate that.

MS. CHRISTENSEN: With that, I have no further questions. Thank you.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman. I just have a few, and it's a Schef Wright few.

EXAMINATION

BY MR. WRIGHT:

Q Hey, Mark. How are you doing?

A I'm good. How are you today?

Q I'm good. Thanks.

A Good.

Q The transmission project is a good project; correct?

A That is correct.

Q And as I understand it, it's -- your interrogatory response says it'll be in service in December of 2017?

A That's correct.

Q And it will not start providing any benefits to customers until January of 2018 as you presently project?

A Correct.

Q Are you committed to completing the project as scheduled without regard to whether the Public Service Commission approves it for recovery through the fuel clause this year?

A We are not committed to the completion of this project. At this point there's a lot riding on this proceeding.

You know, our intent from the beginning was to find a way to make this happen. And the most expeditious way to make this happen, get it into service, provide savings to our customers was to be able to go through the fuel proceeding as we're doing so that that would minimize the length of time until it was in service. So there are other possibilities, yes, but those will take much longer to come into place, and there will be a lot more decisions to be made along the way.

Q So you've got a good project, but you won't do it if you don't get the money through the fuel clause?

A Oh, no. We will move forward with evaluating the project and determine how best that we can put it into place via other mechanisms, rate proceedings, different alternatives as we move forward.

This is a big project for FPU, very significant, a very important project, yes, but it is a big project for FPU.

Q Okay. You'll agree that it won't be used and useful in providing service to FPU's customers before January 1st, 2018, will you not?

A It will provide savings to them on that date.

Q That's not the question I asked. Will you agree that it will not be used and useful in providing service to FPU's customers until that date?

A It will be in service as of that date, correct.

Q You've mentioned -- a couple of times you mentioned, in response to a question by Ms. Christensen, including regulatory proceedings and you made a similar statement a couple of minutes ago.

You could have a rate case with a projected test year of 2018 and get it into base rates at the time that it would be used and useful and serving customers, could you not?

A I don't believe so.

Q Help me out. Are you saying you could not file and prosecute a rate case with a result before now and January 2018?

A A lot of the decisions on doing a rate case and the timing are beyond my ability to make any decisions. I'm not aware of the exact time frame. But as I mentioned, you're making commitments to contractors. At this point it's very important in order to be able to get it into service by 2018.

Q It's November of 2015. We've got 26 months till January of 2018; correct?

A That's correct.

Q And you don't know whether the company could actually prosecute a rate case in 26 months?

A If the decision was made to go that route, taking all factors into consideration, looking at the costs involved, they could, but that would be a decision outside of my scope.

Q Florida Public Utilities does have transmission assets in its base rate as of -- base rate -- rate base as of today; correct?

A That is correct.

Q And you'll agree that recovery of transmission assets through base rates as a rate base item is normal regulatory treatment; correct?

A No. Unfortunately, as we mentioned, we are different. We're small, we're situated different, differently, I'm sorry, and we do have the collection of transmission costs. We even have the collection of distribution, electric distribution costs that run through our fuel docket. So in our collection of fuel charges there is a small amount of distribution charge. There is a probably 10 to 20 percent transmission charge included in fuel in our bills that we receive from our purchased power providers, and then there are the regular energy and capacity charges.

Q Are those transmission and distribution costs recovered through fuel that you just referenced included as part of the payments you make to your power -- purchased power providers?

A Yes, they are.

Q Okay. Do you recover any of your own transmission rate base through the fuel clause?

A At this point we do not.

Q Okay. I'm going to ask you the question that I asked you before: Will you agree that treating a utility's rate base transmission system as rate base recovered through base rates is normal regulatory practice?

A Can you repeat that one more time?

Q Will you agree that recovery of transmission rate base costs through base rates is normal utility regulatory practice in Florida?

A I would agree.

Q Thank you. It would be possible, would it not, for the company to file a rate case, say, sometime next year with a 2017 projected test year and ask for CWIP, construction work in progress, for the transmission rate base for this project?

A I would not know those details. I'm sorry.

Q Okay. Can you answer the question whether it would be possible for the company to do that?

A I would assume that it would be possible, yes.

Q Is your company averse to having a general rate case before the Commission?

A No.

MR. WRIGHT: Great. Thanks. That's all I have.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: Thank you.

EXAMINATION

BY MR. MOYLE:

Q Good morning.

A Good morning.

Q I don't know that we've met. I'm Jon Moyle and I represent the Florida Industrial Power Users Group, and I just have a few questions for you.

A Okay.

Q Can you just describe for me your relationship -- you or your company's relationship with Chesapeake?

A We are a subsidiary of Chesapeake Utilities Corporation that is based in Dover, Delaware.

Q Okay. And Chesapeake, that's a big publicly traded company; is that right?

A It's not the Chesapeake Energy that a lot of people typically think of. Chesapeake Utilities

Corporation is a natural gas, propane company based in Dover, Delaware, and I think we're in the neighborhood of maybe 700 employees companywide.

Q Do you know, is it privately held or publicly traded?

A Publicly traded.

Q On which exchange?

A The New York Stock Exchange, I'm assuming.

Q Do you know the symbol?

A CPK, I believe.

Q And a lot of utilities over the years with rate cases we've had with other utilities, the parent companies will help financially with subsidiaries. Is that the case with Chesapeake and your company? Do they loan you money or invest equity in your company?

A I'm --

MS. KEATING: Mr. Chairman, I'm sorry. Again, I think this is a line of questioning that's starting to wander a bit afield of Mr. Cutshaw's testimony.

MR. MOYLE: He said they're different and it's a small company. I think he opened the door. I can explore the relationship. Are they a small company and they need the money now but they don't have the capital? I mean, that's all I'm trying to do.

CHAIRMAN GRAHAM: I'll let you -- I'll let him answer this question, but let's just not dig down in this hole.

MR. MOYLE: I have a spade, not a shovel.

CHAIRMAN GRAHAM: Sir, if you do know the answer to it, that's fine.

THE WITNESS: Can you repeat the question?

BY MR. MOYLE:

Q Sure. I'm just trying to understand the relationship with the parent company to the subsidiary. And my general question was does the parent company assist financially in terms of providing either debt or equity to Florida Public Utilities?

A My expertise is more in engineering business development, some vague knowledge of the accounting. But as far as the financing portion on how the loaning of money occurs, I could not answer.

Q Okay. And I'm not trying to get expertise. I just want to know do you have an understanding, do they loan them money or provide equity to them? You know, it can be yes or no.

A I would assume yes.

Q And you were having -- not able to answer Mr. Wright's questions about a rate case and said there were others that would have to make that decision; is that right?

A That's correct.

Q Okay. And who would those others be?

A The executive management team within our company would, as they typically do, evaluate all the different parts, the inputs related to conducting a rate case, and also, you know, look at the costs involved that our customers would have to pay for.

Q All right. You had testified that you had -- you would -- I think I wrote it down -- find a way to make it happen, that this was an important project and you wanted to find a way to make it happen. Mr. Wright asked you about rate cases and timing, and I'm not going to retread that, but I did have a specific question. Did you consider filing what they call a limited proceeding before this Commission to ask the Commission to consider this in a limited proceeding?

A I'm not aware -- I'm not sure if that was ever contemplated or not. I was not involved in that.

Q Okay. And with respect to those types of questions, the rate case, neither you or the gentleman that testified yesterday would have information about that? That would be your senior management team; is that right?

A That's correct.

Q Do you have any authority that you would reference to me or this Commission where the Commission -- well, let me start with this. I think you agreed with Mr. Wright that this interconnection is part of a transmission -- it's part of a transmission asset; correct?

A That's correct.

Q Okay. And do you have any authority that you can reference that says this Commission in the fuel clause has allowed the recovery of transmission assets?

A I do not have any specific knowledge or situations in which that has occurred, but I do understand that they have the discretion to look at certain situations, and assuming that it does provide cost savings to customers within the fuel docket, that they can consider that.

Q So no authority, but you think they may have some discretion?

A That's correct.

Q Okay. And you don't know if the fuel clause is a rule or a statute or just something that --

A I understand there is some guidelines associated with that, but I'm not familiar with those details.

Q Okay. Just a couple of other questions. You had said that the anticipated construction of this would wrap up in the end of 2017; is that right?

A That's correct.

Q Most construction projects -- well, that's -- most contracts that I'm familiar with have contingency provisions and not all construction projects come in on time. Would you agree with that?

A That's correct. Yes.

Q Okay. Do you know if there -- if the 2017 date that you're testifying to, does that include a contingency period or not include a contingency period?

A There is a contingency period. And assuming that things are approved in December, they will be able to start the project effective January 1st.

Q Of '16?

A Of '16.

Q Okay. So back to the question, do you know if the contract, if the 2017 finish date, if you will, has the contingency period included or is there a six-month contingency period that could push the contract out to, you know, the middle of '18, the construction contract?

A It is a two-year project with the long lead time items being approximately a year delivery time. And the project engineering has begun, and we feel like, you know, based on the delivery of the long lead time items, that if we're able to begin in January of 2016, we will be able to complete it on or before the end of 2017, which does include some contingency periods in there.

Q Okay. A similar question with respect to your contract with JEA for the purchased power. Are there provisions to extend that contract beyond the end of 2017?

A If we made the decision to extend that, we could do that by mutual agreement. That is not our intent.

Q Okay. And you are aware that if you all thought, hey, this is a good project, we need to move forward with it, you could do that and then subsequently ask this Commission to approve it either in a limited proceeding or in a base rate case. That's another option.

A Yes.

MR. MOYLE: Okay. Thank you. That's all I have.

CHAIRMAN GRAHAM: Staff?

EXAMINATION

BY MS. JANJIC:

Q Good morning, Mr. Cutshaw. Danijela Janjic with Commission staff.

Before I get to the questions, I passed out a courtesy copy of Exhibit 90. It has FPUC's response to staff's third set of interrogatories, No. 15 and 17.

A Got it.

Q Okay. Perfect. In staff's third set of interrogatories, Nos. 15B and 15C, staff asked whether FPUC planned to purchase power from FPL before its contract with JEA expires in December of 2017. FPUC responded that its contract does not allow it to take power from another wholesale provider.

My question is does FPUC anticipate negotiating a purchase contract with either JEA or FPL which enables it to purchase power from the other provider during the term of their contract?

A No. We anticipate submitting -- issuing an RFP shortly to have a new purchased power agreement in place at the beginning of 2018.

Q Okay. Could you please refer to page 7 of your prefiled direct testimony, specifically lines 13 through 15.

A What were those line numbers again?

Q 13 through 15. You stated that the addition of the FPL interconnection will provide much needed redundancy for the Northeast Division. In light of the answer to the previous question, please explain how the

FPL interconnection will provide redundancy to the FPUC system.

A After the completion of the interconnection, we will have two sources of transmission power that will be available to Amelia Island. So we will be able to, as of the beginning of 2018, have two transmission sources that feed Amelia Island as opposed to only one.

As I mentioned in my opening summary, there have been issues with transmission reliability. Since 2010, there have been approximately three hours of time in which the Amelia Island had no power as a result of transmission issues, and we think this additional connection to Florida Power & Light will provide additional reliable transmission service to the island.

Q In response to staff's third set of interrogatories, specifically No. 15A, FPUC stated that the estimated in-service date of FPL interconnection construction is December 2017, which coincides with the expiration of its contract with JEA.

What plans does FPUC have for the interconnection system if at the end of the new contract negotiations it is still limited to taking power only from JEA?

A We anticipate with our RFP that is sent out we will be able to identify a number of additional wholesale power sources within or nearby the State of Florida. And as such, we don't see that there will be any issues with selecting the low cost provider and being able to wheel power to Amelia Island through either the JEA or FPL transmission systems.

Q Mr. Cutshaw, can you please turn to the company's response to staff's third set of interrogatories No. 17.

A Is that an exhibit that is over here?

Q Yes. It was a courtesy copy that was passed out, No. 90. It's the one that has handwritten the name of the witness and party.

A Okay. And this is 15B?

Q I'm sorry?

A 15B?

Q It's 17. It was one of the first ones that was passed out.

A Okay. Interrogatory 17.

Q Yes.

A Okay.

Q Okay. Perfect. Is it correct that the estimated cost for constructing the station, equipment, poles and fixtures, overhead conductors and devices is approximately 3.5 million?

A That is correct.

Q Has anything changed in this estimate since you prepared the interrogatory response?

A No, it has not.

Q And do you anticipate that it's likely to go either up or down in the near future?

A Not to my knowledge. But I'm sure with construction projects this number will not be correct when it's over.

Q In the biographical section of your testimony, specifically page 1, lines 8, through page 2, line 6, you stated you hold a degree in engineering and have responsibility for business development and generation.

A That's correct.

Q From an engineering perspective, can you describe for me the current transmission facilities?

A The existing transmission interconnection with JEA is approximately eight miles of 138 kV transmission that is constructed on a single pole line. It is a dual circuit so that the -- there are actually from JEA two separate 138 kV circuits that run to Amelia Island, but they are constructed on the same pole line.

Q Okay. And what is the age and the life expectancy of those assets?

A The assets were reconstructed around the 2000/2001 time period. They were constructed on concrete poles with new conductors, and those assets have a typical 20- to 30-year, I'm sorry --

Q That's okay.

A -- life expectancy.

Q And what is the capacity of the current transmission facilities to meet future goals -- or its future load? I'm sorry.

A The existing facilities have the capacity to provide adequate supply to Amelia Island from now to many, many, many years in the future. The second supply of transmission facilities will also be constructed so that they are able to provide adequate supply into the future.

Q Assuming the new transmission line is approved, built and placed into service, how will FPUC's customers benefit?

A Again, as I mentioned earlier, not only will they provide -- not only will this line provide them with at least $2.3 million per year in savings, and as you can see from some of the exhibits, that number could go up depending on the development of the purchased power agreements, but not only will it save them that money, there will be additional reliability with having two transmission sources to the island. The three hours of outage time that have occurred over the last six years should not be a problem in the future.

Q In the prior question I asked you to assume approval of the new line. Let's take an opposite view. Assuming the new transmission line is not approved, built and placed into service, how will that decision impact FPUC's customers?

A That decision would result in a possible delay of having any savings. As we discussed, this is a very important project. We want to find a way to make it happen, and our goal at this point is to determine how quickly and most efficiently we can get it into service and then provide those savings to our customers. Should that not occur, we'll have to evaluate what are other alternatives, how can we put it into service, and by what means can we expect recovery?

Q Could you please turn to your testimony on page 9, lines 1 through 6.

A Okay.

Q In this testimony, is it correct to say that FPUC can reasonably project that fuel savings will occur when this interconnection line is built?

A Can you repeat that one time, please?

Q No problem. Is it correct to say that FPUC can reasonably project that fuel savings will occur when this interconnection line is built?

A Yes.

Q And building from what is stated in your testimony and in consideration to your response above on the life expectancy of this facility, is it reasonable to project that the lifetime fuel savings for this project will exceed the project's cost?

A By far, yes.

Q How far? Estimate, please.

MR. MOYLE: I'm going to object to this line of questions because it's all based on stuff that's going to happen in the future. It calls for the witness to speculate how much is he going to save over the life of the project. You know, it all depends on negotiations and prices of gas and things, so it's not based in any kind of facts other than maybe projections.

MS. JANJIC: The exhibit was filed on the savings, so this is the type of stuff that we rely upon, and that's his testimony.

CHAIRMAN GRAHAM: I'm going to allow -- I'm going to allow the question and answer because this is within his expertise, and I guess she's just asking his opinion.

THE WITNESS: So can you ask the question one more time?

MS. JANJIC: Yes, sir.

MS. CHRISTENSEN: Commissioner, may I interject an objection just to note that the savings exhibit was attached to Mr. Young's testimony. And Mr. Young testified that he did not produce that exhibit, that that was produced by a consultant. So it's not only not Mr. Cutshaw's exhibit, it wasn't even produced by the person who was sponsoring it. So I've lodged those objections.

MS. JANJIC: I believe it was stated in the testimony the amount of savings. If you'll give me a moment, we can find it.

(Pause.)

MR. MOYLE: Mr. Chair, the record will speak for itself, but I don't believe this witness was designated as an expert in fuel projections. And if it's a projection that's not even prepared by him, he shouldn't be testifying to it. So we --

CHAIRMAN GRAHAM: Well, let's see what's in his testimony.

MS. KEATING: And, Mr. Chairman, if I may, Mr. Cutshaw has testified about the value of all the projects that are in his testimony, and certainly I think the line of questions that staff is on are fair questions in terms of savings from projects.

BY MS. JANJIC:

Q So is it safe to say that the life --

CHAIRMAN GRAHAM: Did you find it in his testimony?

MS. JANJIC: It seems to be in a redacted response, but can we get a second? I'm sorry.

MS. CHRISTENSEN: Commissioner, if I can help, it was attached to Curtis Young's CDY No. 3, page 10 of 10.

MS. JANJIC: That was the math. But there -- it was in -- he does testify that there will be savings. Just a second.

MS. KEATING: Mr. Chairman, if I may, on page 9 of Mr. Cutshaw's testimony, at the very top of the page he discusses the savings associated with the FPL interconnect. It's certainly within the scope of his testimony.

MS. JANJIC: Okay. Which I believe was the reference that I mentioned when asking at the beginning of the question, I said, "Turn to page 9, lines 1 through 6. May I restate the question?

CHAIRMAN GRAHAM: Please.

MS. JANJIC: Okay.

BY MS. JANJIC:

Q Building from what is stated in your testimony on page 9, lines 1 through 6, is it -- and in consideration to your response above on the life expectancy of this facility, is it reasonable to project that the lifetime fuel savings for this project will exceed the project's cost?

A Yes.

Q And one more question, Mr. Cutshaw, and then I'll be done.

Mr. Cutshaw, is it correct that FPL will be constructing the transmission line with the costs to be reimbursed to FPL by FPUC?

A That's correct.

MS. JANJIC: Nothing further from staff.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Brown.

COMMISSIONER BROWN: Thank you. And thank you for your testimony and your responses to some of these questions.

It appears from your testimony that this interconnection project is a priority of FPUC for reliability purposes and for its customers.

There were a variety of questions asked in different ways about what FPUC would do if the Commission does not approve the interconnection project. So I just want to be clear, is FPUC going to pursue the project irrespective of whether we approve it during the fuel clause?

THE WITNESS: To my knowledge, we will evaluate this project in the context of a rate proceeding in the future and determine if that is in the best interest of the company and our customers.

Obviously with a rate proceeding there's a lot more to consider than one specific project. What we're doing in this proceeding is we're taking this project on its own and bringing it before the Commission to say we think with this we'll be able to save our customers money, we'll be able to get it in place and in service more quickly without a lot of the other distractions that would be involved with considering it in the context of a rate proceeding.

COMMISSIONER BROWN: Okay. If I may. And is there an alternative to that? Particularly could you renew the JEA agreement or another wholesale purchased power agreement or --

THE WITNESS: I mean, we are also going to, during this time period, evaluate who our next wholesale provider will be, and we anticipate with that change there will be considerable changes or savings for our customers. So not only are we going to do this project which will provide savings, we will also be looking at a different wholesale power contract that will provide additional savings, as well as other projects. We're constantly working on, through our consultants and our legal staff, we're looking at other ways, other projects that we can bring into to place, like Eight Flags Energy, that will continue to provide savings to our customers.

COMMISSIONER BROWN: And get more favorable terms, et cetera.

THE WITNESS: That's correct.

COMMISSIONER BROWN: And you mentioned something about an RFP going out. When is the utility thinking of issuing that?

THE WITNESS: Typically a two-year time period is the minimum to be able to go out, look at the marketplace, look at different providers, and then put out the RFP, do negotiations, and then select a new wholesale provider in the future. So we will be doing that beginning the first of 2016.

COMMISSIONER BROWN: Thank you so much.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I just have a few very general questions.

Good morning. Mr. Cutshaw, do I remember correctly that you have participated in prior rate case proceedings for FPUC?

THE WITNESS: Yes, you do.

COMMISSIONER EDGAR: As a witness and attending customer meetings and other related activities?

THE WITNESS: Yes. Yes.

COMMISSIONER EDGAR: Are you -- and that FPUC's rates right now are subject to a current settlement agreement?

THE WITNESS: Yes.

COMMISSIONER EDGAR: Are you generally familiar with the terms of that settlement?

THE WITNESS: Vaguely.

COMMISSIONER EDGAR: Generally?

THE WITNESS: Yes.

COMMISSIONER EDGAR: Do you know the date that that settlement extends to?

THE WITNESS: Not in -- no, I do not.

COMMISSIONER EDGAR: Okay. My memory is approximately the end of next calendar year, but I would need to verify that. And it was only a little over a year ago. Time flies.

THE WITNESS: Yes, it does.

COMMISSIONER EDGAR: So if -- and are you aware of when FPUC would be able to file for a new rate case or for a test year for a new rate case under the terms of the settlement?

THE WITNESS: I am not. I'm sorry.

COMMISSIONER EDGAR: Okay. That's okay. Is it your understanding that when FPUC is able under the terms of settlement to file for a full rate case, that there might be other issues that would be considered in a rate case beyond the project that is before us for potential fuel clause recovery?

THE WITNESS: Yes.

COMMISSIONER EDGAR: And with your experience participating in other rate cases, would you consider it a possibility that an overall rate case could result in increases for customers for other items?

THE WITNESS: Yes, it could.

COMMISSIONER EDGAR: All right. Thank you.

THE WITNESS: Very, very possible.

COMMISSIONER EDGAR: Thank you.

CHAIRMAN GRAHAM: Redirect.

MS. KEATING: No redirect, Mr. Chairman.

CHAIRMAN GRAHAM: Exhibits?

MS. KEATING: Mr. Cutshaw has no exhibits.

CHAIRMAN GRAHAM: OPC, did you have exhibits?

MS. CHRISTENSEN: Yes. I would move Exhibit

125.

CHAIRMAN GRAHAM: Seeing no objections, we'll move 125 into the record.

(Exhibit 125 admitted into the record.)

I don't think there's any other exhibits, so, Mr. Cutshaw, thank you very much for your testimony.

THE WITNESS: Thank you.

MS. KEATING: Thank you. If he may be excused. And also, Mr. Chairman, if I may ask, this concludes FPUC's witnesses. We are not involved in the remaining issues that are going to be pursued during the remainder of the fuel docket, and I wondered if it might be permissible that counsel for FPUC might also be excused.

CHAIRMAN GRAHAM: Who might that be?

(Laughter.)

Sure.

MS. KEATING: Thank you, Mr. Chairman. I appreciate it.

CHAIRMAN GRAHAM: Okay. Let's move on to our next witness.

MR. BADDERS: Chairman Graham, the next witness is Mr. Ball on behalf of Gulf Power.

Chairman Graham, I'll note for the record that he was present yesterday when the witnesses were sworn and he took the oath.

Whereupon,

HERBERT RUSSELL BALL

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

EXAMINATION

BY MR. BADDERS:

Q Mr. Ball, would you please state your name and business address for the record.

A My name is Herbert Russell Ball, and my business address is Gulf Power Company, 1 Energy Place, Pensacola, Florida 32520.

Q And what is your job title?

A My job title is Fuel Manager for Gulf Power Company.

Q Thank you. Are you the same H. R. Ball who prefiled true-up testimony on March 3rd, 2015; September -- projection testimony on September 1, 2015; and estimated/actual testimony on August 4th, 2015?

A Yes.

Q Do you have any changes or corrections to that testimony?

A No.

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

A Yes.

MR. BADDERS: Chairman Graham, it's my understanding that at least two parties have requested voir dire of this witness. Gulf would offer this witness as an expert with regard to fuel procurement, hedging, and all of the other matters listed on our October 14th, 2015, notice of areas of expert witness expertise, and he's available for voir dire.

CHAIRMAN GRAHAM: Mr. Moyle, I think you're first up.

MR. MOYLE: Thank you, Mr. Chairman. Just a few questions.

VOIR DIRE EXAMINATION

BY MR. MOYLE:

Q You -- in college you were a chemistry major; is that right?

A I have a Bachelor's of Science degree -- major in chemistry, and I have a Master's Degree in business administration.

Q Okay. And the filing that your company made on October 14th which designated your areas of expertise, have you seen that? Are you aware of that filing?

A I have seen it, yes.

Q Okay. Is it accurate in your opinion?

A Yes. In my opinion, yes.

Q So there's nothing for which you would express expertise beyond what was set forth in this filing as it relates to energy matters? You might be a great fisherman, but, you know, it's limited to energy matters.

A You know, I guess I wouldn't say that's all inclusive, but I think it fairly represents what I'm testifying to in this proceeding.

Q So you said it is all inclusive? I just didn't hear you.

A I said, no, I don't necessarily say that it's all inclusive, but I think it's fairly representative of what I'm testifying to in this proceeding.

Q Okay. What other areas would you have expertise in that related to energy that --

A Well, I guess my point is there may be some things that I'm not aware of that you may have questions about, so I'm just -- I'm not stating that that includes every possible item that could be addressed in this. But regarding my direct testimony, I think that, you know, I am -- I do provide expertise in the areas that I provided direct testimony.

Q And I've read your testimony. To my reading of your testimony, most of what you're suggesting is facts to say here's how we hedge, here are the results of the hedge. You don't have a lot of opinion testimony. Would you agree with that general assessment?

A I wouldn't say that I have a lot of opinions about hedging. I just state what Gulf does in regards to hedging in my testimony, and I try to explain the mechanism of the Risk Management Plan that we filed and how that's implemented by Gulf and what we expect the results to be.

Q Okay. And so some of the other utilities, when they filed a similar document, they used the phrase "regulatory policy considerations related to hedging." That phrase is not in your notice, so I assume that that's not an area of expertise that you're suggesting be considered?

A Well, I think if you look at the Risk Management Plan that's an exhibit to that testimony, you'll find that we do -- or that I do state that I believe that the Risk Management Plan that Gulf files is an appropriate and reasonable implementation of the Commission's hedging order.

Q Anything else?

A I'm not aware of what you're asking about as far as anything else.

Q Related to areas of expertise. I mean, if I ask you questions about policy and start digging down into hedging, are you going to be comfortable answering those?

A I'll do the very best that I can.

MR. MOYLE: Okay. All right. We don't have an objection.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: We don't have any objection. I have no voir dire for Mr. Ball. Thank you.

MR. BADDERS: Then we would move to move into the record the prefiled direct testimony of H. R. Ball as though read.

CHAIRMAN GRAHAM: We will move Mr. Ball's direct testimony into the record as though read.

EXAMINATION

BY MR. BADDERS:

Q Mr. Ball, do you also have five exhibits attached to your testimony?

A Yes.

Q Do you have any changes or corrections to those exhibits?

A No.

MR. BADDERS: I'll note for the record that those exhibits have already been identified as exhibits -- I believe it's 35 through 39.

CHAIRMAN GRAHAM: Duly noted.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibits of
H. R. Ball
Docket No. 150001-EI
Date of Filing: March 3, 2015

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

A. My name is Herbert Russell Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in 1978 with a Bachelor of Science Degree (Chemistry major) and again in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power Company (MPC) at Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Corporate Office and worked in the Fuel Department as a Fuel Business Analyst. In 1987 I was promoted and returned to Plant Daniel as the Supervisor of Chemistry and Regulatory Compliance. In 1998 I transferred to Southern Company Services, Inc. in Birmingham, Alabama and took the position of Supervisor of Coal Logistics. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern electric system (SES). I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's participation in the Intercompany Interchange Contract (IIC) between Gulf and the other operating companies in the Southern electric system (SES).

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2014 through December 31, 2014. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

A. Yes, I have.

Counsel: We ask that Mr. Ball's exhibit consisting of four schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2014 through December 2014, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $493,087,844 which is $13,457,842 or 2.81% above the projected amount of $479,630,002. Actual net power transaction energy was 12,020,038,884 kWh compared to the projected net energy of 12,180,797,600 kWh or 1.32% below projections. The resulting actual average cost of 4.1022 cents per kWh was 4.18% above the projected cost of 3.9376 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2014 included in Appendix 1 of Witness Boyett's exhibit. The higher total fuel and net power transaction expense is attributed to a higher per unit cost (cents per kWh) for available energy than projected for the period offset somewhat by a lower quantity of energy (kWh) available after economy and other power sales are deducted. The total quantity of power sales is higher than projected as a result of Gulf's available energy being lower cost than other energy sources which resulted in these generating assets being economically dispatched to serve system load. The actual total cost of available energy was above projections by $49,166,435 or 8.62% and the total quantity of available energy was above projections by 2,584,599,499 kWh or 17.29%. The actual cost per kWh of available energy was 3.531 cents per kWh which is 7.39% lower than the projected cost of 3.813 cents per kWh. The lower cost per kWh for available energy is due primarily to the mix of available energy containing a higher percentage of purchased power.

These energy purchases were primarily from lower cost gas fired generating units that Gulf has secured under Purchase Power Agreements (PPA's).

Q. During the period January 2014 through December 2014, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of system net generation was $403,824,215 or 4.63% above the projected amount of $385,956,107. Actual generation was 9,940,645,000 kWh compared to the projected generation of 9,567,137,000 kWh, or 3.90% above projections. The resulting actual average fuel cost of 4.0624 cents per kWh was 0.70% above the projected fuel cost of 4.0342 cents per kWh. The higher total fuel expense is attributed primarily to the quantity of kWh generated being higher than projected for the period. The actual quantity of fuel consumed was 93,122,696 MMBTU which is 4.65% above the projected quantity of 88,985,589 MMBTU. The percentage of energy generated from coal fired resources was 59.01%, which was 0.89% lower than the projected percentage of 59.54%. The weighted average fuel cost for natural gas was $3.44 cents per kWh, which is 1.47% above the projected cost of $3.39 cents per kWh. The weighted average fuel cost for coal, plus lighter fuel, was $4.49 cents per kWh, which is 0.22% higher than the projected cost of $4.48 cents per kWh. This information is found on Schedule A-3, period-to-date, for the month of December 2014 included in Appendix 1 of Witness Boyett's exhibit.

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

A. The total actual cost of coal purchased was $232,648,702 (line 17 of Schedule A-5, period-to-date, for December 2014) compared to the projected cost of $244,846,800 or 4.98% below the projected amount. The lower total coal cost was due to the actual weighted average price of coal purchased being $83.92 per ton which is 7.10% below the projected price of $90.33 per ton. Gulf purchased some lower cost spot coal during the current period.

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

A. The total cost of coal burned was $258,875,502 (line 21 of Schedule A-5, period-to-date, for December 2014). This is 3.20% higher than the projection of $250,845,394. The higher total coal burn cost was due to the quantity of coal burned being 7.72% above projections offset somewhat by the actual weighted average coal burn cost being $88.48 per ton which is 4.19% below the projected burn cost of $92.35 per ton for the period.

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total actual cost of natural gas burned for generation was $138,908,611 (line 34 of Schedule A-5, period-to-date, for December 2014). This is 7.24% above the projection of $129,524,607. The higher total gas cost was due to the actual weighted average gas burn cost being

$5.24 per MMBTU, which is 6.29% higher than the projected burn cost of $4.93 per MMBTU.

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. Gulf Power's fuel strategy in 2014 complied with the Risk Management Plan filed on August 2, 2013.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of coal being delivered to Gulf's coal-fired generating units during the period?

A. Yes. The supply of coal and associated transportation to Gulf's generating plants is generally secured through a combination of long-term contracts and spot agreements as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These early purchase commitments and the planned diversity of fuel suppliers are designed to provide a more reliable source of coal to the generating plants. The result was that Gulf's coal-fired generating units had an adequate supply of fuel available at all times at a reasonable cost to meet the electric generation demands of its customers.

Q. For coal shipments during the period, what percentage was purchased on the spot market and what percentage was purchased using longer-term contracts?

A. As shown in Schedule 1 of my exhibit, total coal shipments for the period amounted to 2,772,383 tons. Gulf purchased 47% of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year or less. Spot coal purchases are typically needed to allow a portion of the purchase quantity commitments to be adjusted in response to changes in coal burn that may occur during the year due either to economic or operational reasons. Gulf purchased 53% of its 2014 coal supply under longer-term contracts. Longer-term contracts provide a reliable base quantity of coal to Gulf's generating units with firm pricing terms. This limits price volatility and increases coal supply consistency over the term of the agreements. Schedule 1 of my exhibit consists of a list of contract and spot coal shipments to Gulf's generating plants for the period as reported on the monthly FPSC 423 reports.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in stable coal prices for the period?

A. Yes. Coal cost volatility was mitigated through compliance with the Risk Management Plan. Gulf uses physical hedges to reduce price volatility in its coal procurement program. Gulf purchases coal and associated transportation at market price through the process of either issuing formal requests for proposals to market participants or occasionally for small quantity spot purchases through informal proposals. Once these confidential bids are received, they are evaluated against other similar proposals using standard contract terms and conditions. The least cost acceptable alternatives are selected and firm purchase agreements are negotiated with the successful bidders. Gulf purchased coal and coal transportation using a combination of firm price contracts and purchase orders that either fix the price for the period or escalate the price using a combination of government published economic indices. Schedule 2 of my exhibit provides a list of the contract and spot coal shipments for the period and the weighted average price of shipments under each purchase agreement in $/MMBTU. Because of the more balanced mix of longer-term contract coal purchase agreements and spot purchase agreements during the period, Gulf was able to take advantage of lower market pricing for spot coal. The variance between the estimated purchase price of coal and the actual price for the period was 7.10% below projected as reported on line 16 of Schedule A-5, period to date, for the month of December 2014.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of natural gas being delivered to Gulf's gas-fired generating units at a reasonable price during the period?

A. Yes. The supply of natural gas and associated transportation to Gulf's generating plants was secured through a combination of long-term purchase contracts and daily gas purchases as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These natural gas purchase agreements price the supply of gas at market price as defined by published market indices. Schedule 3 of my exhibit compares the actual monthly weighted average purchase price of natural gas delivered to Gulf's generating units to a market price based on the daily Florida Gas Transmission Zone 3 published market price plus an estimated gas storage and transportation rate based on the actual cost of gas storage and transportation Gulf paid during the period. The purpose of early natural gas procurement commitments, the planned diversity of natural gas suppliers, and providing gas suppliers with market pricing is to provide a more reliable source of gas to Gulf's generating units. The result was that Gulf's gas-fired generating units had an adequate supply of fuel available at all times at a reasonable price to meet the electric generation demands of its customers.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in lower volatility of natural gas prices for the period?

A. Yes. Gulf purchases physical natural gas requirements at market prices and swaps the market price on a percentage of these purchases for firm prices using financial hedges. The objective of the financial hedging program is to reduce upside price risk to Gulf's customers in a volatile price market for natural gas. In 2014, Gulf's weighted average cost of natural gas purchases for generation was $5.21 per MMBTU. This was 5.68% higher than the projection of $4.93 per MMBTU (line 29 of Schedule A-5, period-to-date, for December 2014). The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my exhibit, the calculated volatility of Gulf's delivered cost of natural gas for the Smith 3 and Central Alabama PPA combined cycle generating units for the period is represented by a variance of 0.33 and standard deviation of 0.58. By contrast, the calculation of the volatility of Gulf's hedged delivered cost of natural gas for the period yields a variance of 0.08 and a standard deviation of 0.28. The lower values for variance and standard deviation for the set of hedged prices demonstrates that Gulf's financial hedging program is achieving the goal of reducing the volatility of natural gas cost to the customer.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or financial instrument?

A. Gulf Power hedged 34,910,000 MMBTU of natural gas in 2014 using financial instruments. This represents 59% of Gulf's 58,867,934 MMBTU of actual gas burn for Smith Unit 3 plus the actual gas burn for the Central Alabama PPA combined cycle unit during the period. The total amount of natural gas burn by month for these units is reported on Schedule 4 of my exhibit.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged primarily using financial swap contracts that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. Of the volume of gas hedged for the period, 31,840,000 or 91.1% was hedged using financial swap contracts and 3,070,000 or 8.9% was hedged using option contracts.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2014 through December 2014?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2014 hedging program resulted in a net financial gain of $1,910,889 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2014 included in Appendix 1 of Witness Boyett's exhibit.

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

A. No.

Q. During the period January 2014 through December 2014 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is ($126,131,992) or 39.49% above the projected amount of ($90,423,400). Total kilowatt hours of power sales were (5,515,215,215) kWh compared to estimated sales of (2,769,857,000) kWh, or 99.12% above projections. The resulting average fuel cost of power sold was 2.2870 cents per kWh or 29.95% below the projected amount of 3.2646 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2014 included in Appendix 1 of Witness Boyett's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the projection?

A. The higher total credit to fuel expense from power sales is attributed to the higher total quantity of energy sales (kWh) than projected. The more favorable position of Gulf's generating assets in system economic dispatch to serve load resulted in a greater quantity of energy sales. This was offset somewhat by a below budget fuel reimbursement rate (cents per kWh) paid to Gulf for typical power sales.

Q. During the period January 2014 through December 2014, how did Gulf Power Company's recoverable fuel cost of purchased power compare to projected cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $217,315,321 or 18.05% above the estimated amount of $184,081,492. Total kilowatt hours of purchased power were 7,594,609,099 kWh compared to the estimate of 5,383,517,600 kWh or 41.07% above projections. The resulting average fuel cost of purchased power was 2.8614 cents per kWh or 16.32% below the estimated amount of 3.4194 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2014 included in Appendix 1 of Witness Boyett's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of kWh at attractive prices to supplement its own generation to meet load demands. This includes energy supplied to Gulf through purchase power agreements. The average fuel cost of energy purchases per kWh was lower than projected as a result of lower-cost energy being made available to Gulf for purchase during the period.

Q. Should Gulf's recoverable fuel and purchased power cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's lighter oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf adhered to its Risk Management Plan for Fuel Procurement and accomplished the objectives established by the plan. Through its participation in the integrated Southern electric system, Gulf is able to purchase affordable energy from pool participants and other sellers of energy when needed to meet load and during times when the cost of purchased power is lower than energy that could be generated internally. Gulf is also able to sell energy to the pool when excess generation is available and return the benefits of these sales to the customer. These energy purchases and sales are governed by the IIC which is approved by the Federal Energy Regulatory Commission (FERC). Gulf also purchases power when economically attractive under the terms of several external purchase power agreements which have been reviewed and approved by the Commission.

Q. During the period January 2014 through December 2014, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual total capacity payments for the January 2014 through December 2014 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Boyett's Exhibit, was $63,345,952. Gulf's total re-projected net purchased power capacity cost for the same period was $62,478,533, as indicated on line 4 of Schedule CCE-1B of Witness Boyett's exhibit filed July 25, 2014. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $867,419 or 1.39% higher than the re-projected amount. This higher actual cost is due to Gulf having higher capacity costs under its purchased power agreements than the re-projected amount for the 2014 recovery period.

Q. Was Gulf's actual 2014 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC in which Gulf has been a participant for many years. Gulf's participation in the integrated Southern electric system that is governed by the IIC has produced and continues to produce substantial benefits for Gulf's customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews. Per contractual agreement in the IIC, Gulf and the other SES operating companies are obligated to provide for the continued operation of their electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner. The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2014, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve levels are available to provide reliable electric service to customers. This cost has been properly allocated to Gulf pursuant to the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
H. R. Ball
Docket No. 150001-EI
August 4, 2015

Q. Please state your name and business address.

A. My name is Herbert Russell Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?
A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

Q. What is the purpose of your testimony in this docket?
A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2015 through December 2015 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2015 through June 2015 and projected fuel and net power transaction costs for July 2015 through December 2015. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. I have no exhibits I am sponsoring as part of this testimony.

Q. During the period January 2015 through December 2015 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $431,021,459 which is $10,806,260 or 2.45% below the original projected amount of $441,827,719. The lower total fuel and net power transaction expense for the period is attributed to higher fuel revenue from power sales offset somewhat by a higher total fuel cost of available energy. The resulting average per unit fuel cost is projected to be 3.5539 cents per kWh or 2.48% lower than the original projection of 3.6441 cents per kWh. The lower average per unit fuel and net power transactions cost (cents per kWh) is attributed to a lower per unit fuel cost of available energy for the period driven primarily by lower costs for purchased power, offset somewhat by a lower per unit fuel cost and gains on power sales. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 21.

Q. During the period January 2015 through December 2015 how will Gulf Power Company's recoverable total fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable total fuel cost of generated power for the period is $330,357,916 which is $50,288,197 or 17.96% above the original projected amount of $280,069,719. Total generation is expected to be 8,291,757,000 kWh compared to the original projected generation of 7,527,320,000 kWh or 10.16% above original projections. The resulting average fuel cost is expected to be 3.9842 cents per kWh or 7.08% above the original projected amount of 3.7207 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the total fuel cost of generated power and the current projection?

A. The higher total fuel expense is due to higher average per unit fuel costs (cents/kWh), including financial hedging settlements, combined with a higher than originally projected quantity of generated power (kWh).

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2015?

A. The total fuel cost of system net generation for the first six months of 2015 was $151,625,468 which is $486,399 or 0.32% lower than the projected cost of $152,111,867. On a fuel cost per kWh basis, the actual cost was 3.59 cents per kWh, which is 6.51% lower than the projected cost of 3.84 cents per kWh. This lower than projected cost of system generation on a cents per kWh basis is due to fuel cost in $/MMBtu being 8.35% lower than projected, offset somewhat by heat rate (Btu/kWh) of the generating units operating being 1.87% higher than projected. The lower price of fuel is a result of lower market prices for natural gas than projected for the period offset somewhat by coal fired units operating at reduced efficiency levels during the period. This information is found on Schedule A-3 Period to Date of the June 2015 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2015?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2015 was $98,957,646 which is $16,161,826 or 19.52% higher than the projection of $82,795,820. The total coal fired generation was 2,345,148 MWH which is 13.77% higher than the projection of 2,061,382 MWH for the period. On a fuel cost per kWh basis, the actual cost was 4.22 cents per kWh which is 4.98% higher than the projected cost of 4.02 cents per kWh. The higher than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 16.69% above the estimated burn for the period. The higher per kWh cost of coal fired generation is due to the weighted average heat rate (Btu/kWh) of the coal fired generating units that operated being 2.56% higher than projected combined with actual coal prices (including boiler lighter) being 2.41% higher than projected on a $/MMBtu basis. This information is found on Schedule A-3 Period to Date of the June 2015 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are higher due to a change in the timing and mix of contract shipments to Gulf's coal fired generating plants.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2015?

A. The total cost of natural gas burned for generation for the first six months of 2015 was $52,064,038 which is $16,851,858 or 24.45% lower than Gulf's projection of $68,915,896. The total gas fired generation was 1,866,594 MWH which is 1.02% lower than the projection of 1,885,886 MWH for the period. The total cost of natural gas burned for generation is lower than the forecast due to lower prices for gas combined with lower gas fired generation for the period. On a cost per unit basis, the actual cost of gas fired generation was 2.79 cents per kWh which is 23.56% lower than the projected cost of 3.65 cents per kWh. Actual natural gas prices were $4.21 per MMBtu or 20.86% lower than the projected cost of $5.32 per MMBtu. The gas fired unit heat rate (Btu/KWH) was 4.09% less or more efficient than projected. This information is found on Schedule A-3 Period to Date of the June 2015 Monthly Fuel Filing.

Q. For the period January 2015 through June 2015, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 16,600,000 MMBtu of natural gas for the period. This equates to 65.5% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 25,342,828 MMBtu. This amount is the sum of the Plant Smith Unit 3 burn as reported on

Schedule A-3 Period to Date of the June 2015 Monthly Fuel Filing and the Central Alabama PPA natural gas burn for the period.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. The swaps settled against either a NYMEX Last Day price or Gas Daily price. The total amount of gas hedged for the period was hedged using financial swaps.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were incurred. Gulf's gas hedging program generated a hedging settlement loss of $22,429,164 for the period January through June 2015. This information is found on Schedule A-1, Period to Date, line 2 of the June 2015 Monthly Fuel Filing.

Q. During the period January 2015 through December 2015 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost and gains on power sales for the period are $(64,151,453) or 33.74% above the original projected amount of $(47,966,000). Total kilowatt hours of power sales is expected to be (3,535,982,291) kWh compared to the original projection of (1,503,711,000) kWh or 135.15% above projections. This current projection of fuel cost of power sold is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 18.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost and gains on power sales and the current projection?

A. The greater total credit to fuel expense from power sales is attributed to a significantly higher quantity of power sales than originally projected, offset somewhat by a lower reimbursement rate (cents per kWh) for power sales. The currently projected price for the fuel cost and gains on power sales is 1.8142 cents/kWh which is 43.12% lower than the original projection of 3.1898 cents/kWh. The lower projected fuel reimbursement rate for power sales during the period are due to lower projected fuel costs associated with the units that are projected to set system pool interchange rates for power sales.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2015?

A. The total fuel cost of power sold for the first six months of 2015 was $(33,067,652) which is $(9,562,651) or 40.68% higher than the projection of $(23,505,000). The quantity of power sales for the period was 207.22% higher than projected. The actual cost was 1.4091 cents per kWh which is 54.21% below the projected cost of 3.0771 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2015 Monthly Fuel Filing.

Q. During the period January 2015 through December 2015 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $164,814,996 or 21.41% below the original projected amount of $209,724,000. The total amount of purchased power is expected to be 7,372,348,747 kWh compared to the original projection of 6,100,957,000 kWh or 20.84% above projections. The resulting average fuel cost of purchased power is expected to be 2.2356 cents per kWh or 34.97% below the original projected amount of 3.4376 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 13.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of lower cost energy to supplement its own generation to meet load demands. The lower projected price per kWh for purchased power is due to lower natural gas market prices for the period.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2015?

A. The total fuel cost of purchased power for the first six months of 2015 was $76,895,995 which is $9,265,005 or 10.75% lower than our projection of $86,161,000. The lower than projected purchased power expense is due to the actual price of purchases being lower than projected offset somewhat by a greater quantity of purchases made. Purchased power quantity is 58.30% higher due to higher demand and the availability of lower cost energy purchases to meet this demand. On a fuel cost per kWh basis, the actual cost was 1.9721 cents per kWh which is 43.62% lower than the projected cost of 3.4980 cents per kWh. The majority of these purchases are from Gulf's PPA which is a contract associated with a gas fired generating unit. This information is found on Schedule A-1, Period to Date, line 12 of the June 2015 Monthly Fuel Filing.

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

A. No.

Q. Were Gulf Power's actions through June 30, 2015 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes. Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

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

A. No.

Q. During the period January 2015 through December 2015, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Boyett's testimony, Gulf's total current net capacity payment projection for the January 2015 through December 2015 recovery period is $88,526,101. Gulf's original projection for the period was $88,596,724 and is shown on Line 4 of Schedule CCE-1 filed August 22, 2014. The difference between these projections is $70,623 or 0.08% less than the original projection of net capacity payments. The variance is due to an increase in projected market capacity revenues during the period.

Q. How did the total projected net capacity transactions cost compare to the actual cost for the first six months of 2015?

A. Actual net capacity costs during the first six months of 2015 were $44,382,540 (from Schedule A-12 of the June 2015 Monthly Fuel Filing) which is $3,678 lower than projected amount of $44,378,862 for the period (from Line 2 of Schedule CCE-1 filed August 22, 2014).

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 150001-EI
Date of Filing: September 1, 2015

Q. Please state your name and business address.
A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.
A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern

electric system. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2016 through December 31, 2016. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes, I have four separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–2) consists of a schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections. The second exhibit (HRB-3) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on April 7, 2015 and assigned Document Number DN 01913-15 (redacted) and 01912-15 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August through December 2014 in compliance with Order No. PSC-08-0316-PAA-EI. The third exhibit (HRB-4) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 14, 2015 and assigned Document Number DN 05106-15 (redacted) and 05102-15 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January through July 2015 in compliance with Order No. PSC-08-0316-PAA-EI. The fourth exhibit (HRB-5) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement." This exhibit was filed with the Commission Clerk pursuant to a separate request for confidential classification on August 4, 2015 and assigned Document Number DN 04935-15 (redacted) and 04906-15 (confidential information). The risk management plan sets forth Gulf Power's fuel procurement strategy and related hedging plan for the upcoming calendar year. Through its petition in this docket, Gulf Power is seeking the Commission's approval of the Company's "Risk Management Plan for Fuel Procurement" as part of this proceeding.

Counsel: We ask that Mr. Ball's four exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-2), _____ (HRB-3), _____ (HRB-4), and_____ (HRB-5) respectively.

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2016 through December 2016 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $431,051,133. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2016 period compare to the updated projection of fuel cost for the same period in 2015?

A. The total updated cost of fuel and net power transactions for 2015, reflected on Schedule E-1B-1 line 21 of Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $431,021,459. The projected total cost of fuel and net power transactions for the 2016 period reflects an increase of $29,674 or 0.01% more than the same period in 2015. On a fuel cost per kWh basis, the 2015 projected cost is 3.5539 cents per kWh and the 2016 projected fuel cost is 3.5937 cents per kWh, an increase of 0.0398 cents per kWh or 1.12%.

Q. What is Gulf's projected recoverable total fuel cost of generated power for the period?

A. The projected total cost of fuel to meet system generated power needs in 2016 is $289,255,133. The projection of fuel cost of system generated power for 2016 is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 5.

Q. How does the projected total fuel cost of generated power for the 2016 period compare to the updated projection of fuel cost for the same period in 2015?

A. The total updated cost of fuel to meet 2015 system generated power needs, reflected on Schedule E-1B-1, line 6 of Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $330,357,916. The projected total cost of fuel to meet system net generation needs for the 2016 period reflects a decrease of $41,102,783 or 12.44% less than the same period in 2015. Total system net generation in 2016 is projected to be 8,228,439,000 kWh, which is 63,318,000 kWh or 0.76% lower than is currently projected for 2015. On a fuel cost per kWh basis, the 2015 projected cost is 3.9842 cents per kWh and the 2016 projected fuel cost is 3.5153 cents per kWh, a decrease of 0.4689 cents per kWh or 11.77%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower projected cost of coal and natural gas (includes estimated hedging settlement costs) fired generation (cents/kWh) for the 2016 period. Weighted average coal burned price for 2015 as reflected on Schedule E-3, line 29 of Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $81.96 per ton. Weighted average coal burned price for 2016, as reflected on Schedule

E-3, line 29 of the exhibit to Witness Boyett's testimony, is projected to be $74.49 per ton. This reflects a cost decrease of $7.47 per ton or 9.11%. Several of Gulf's coal supply contracts have or will expire by the end of 2015 and these are projected to be replaced with lower priced coal supply agreements. Gulf's coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these contracts will cover a portion of Gulf's 2016 projected coal burn needs. The remaining coal supply needs will be purchased on the spot market. Weighted average natural gas price for 2015, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $4.11 per MMBtu. When the cost of natural gas hedging settlements (Schedule E-1-B1, line 1a) is included in the total delivered gas cost, the 2015 projected cost is $5.76 per MMBtu. Weighted average natural gas price for 2016, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett's testimony, is projected to be $4.98 per MMBtu. This is a decrease in price of $0.78 per MMBtu or 13.54%. As reflected on Schedule E-3, lines 40 and 41 of the exhibit to Witness Boyett's testimony, the projected fuel cost of Gulf's coal fired generation is 3.59 cents per kWh and the projected fuel cost of Gulf's gas fired generation is 3.42 cents per kWh for the 2016 period. The generation mix in 2015, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be 53.03% coal and 46.66% gas. The generation mix in 2016, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony, is projected to be 55.87% coal and 43.83% gas. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the

2015 projection period is $760,877 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be 3.06 cents per kWh. The total projected cost for landfill gas in 2016 is $758,264 and the total facility generation is projected to be 24,788,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony, is projected to be 3.06 cents per kWh.

Q. Does the 2016 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under both existing and new negotiated coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements. Details of Gulf's fuel procurement strategy are included in the "Risk Management Plan for Fuel Procurement" filed as exhibit _____ (HRB-5) to this testimony.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm pipeline capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect its customers from fuel price volatility?

A. As detailed in Gulf's "Risk Management Plan for Fuel Procurement," natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indices. Gulf's "Risk Management Plan for Fuel Procurement" is a reasonable and appropriate strategy for protecting its customers from fuel price volatility while maintaining a reliable supply of fuel for the operation of its electric generating resources.

Q. What are the results of Gulf's fuel price hedging program for the period January 2015 through July 2015?

A. Gulf's coal price hedging program has successfully managed the price it pays for coal under its coal supply agreements for this period. Gulf has also had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Pursuant to Order No. PSC-08-0316-

PAA-EI, Gulf filed a "Hedging Information Report" with the Commission on April 7, 2015 and also on August 14, 2015 detailing its natural gas hedging transactions for August 2014 through July 2015. As noted earlier, I am sponsoring these reports as exhibits ______ (HRB-3 and HRB-4) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2015 through 2016?

A. Yes. Gulf has natural gas financial hedges in place for 2015 to adequately mitigate price risk. Gulf currently has natural gas hedges in place for 2016 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer and protect against unanticipated dramatic price increases in the natural gas market.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that consider both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market by entering into financial hedge agreements whose total quantity exceed the projected natural gas burn for the period. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant and the gas fired PPA units for which Gulf has tolling agreements. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the IIC. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What are Gulf's projected recoverable fuel cost and gains on power sales for the 2016 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $86,889,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2016 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2015?

A. The total updated recoverable fuel cost and gains on power sales in 2015, reflected on Schedule E-1B-1, line 18 of Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $64,151,453. The projected recoverable fuel cost and gains on power sales in 2016 represents an increase of $22,737,547 or 35.44%. Total quantity of power sales in 2016 is projected to be 3,370,149,000 kWh, which is 165,833,291 kWh or 4.69% less than currently projected for 2015. On a fuel cost per kWh basis, the 2015 projected cost is 1.8142 cents per kWh and the 2016 projected fuel cost is

2.5782 cents per kWh, which is an increase of 0.7640 cents per kWh or 42.11%. The higher total credit to fuel expense from power sales is attributed to a higher fuel reimbursement rate (cents per kWh) for power sales as a result of higher marginal fuel prices for units operating to meet incremental system loads partially offset by a decreased quantity of energy sales for the period. The marginal fuel costs to operate Gulf generating units that run to meet power sales requirements are passed on to the purchasers of power and are reflected in the higher rate (cents/kWh) for the fuel cost and gains on power sales.

Q. What is Gulf's projected total cost of purchased power for the period?

A. Gulf's projected recoverable cost for energy purchases is $228,685,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2016 period compare to the projected purchased power cost for the same period in 2015?

A. The total updated cost of purchased power to meet 2015 system needs, reflected on Schedule E-1B-1, line 13 of Witness Boyett's testimony filed in this docket on August 4, 2015, is projected to be $164,814,996. The projected cost of purchased power to meet system needs in 2016 is $63,870,004 or 38.75% higher than is currently projected for 2015. The total quantity of purchased power in 2016 is projected to be 7,136,326,000 kWh, which is 236,022,747 kWh or 3.20% lower than is currently projected for 2015. On a fuel cost per kWh basis, the 2015 projected cost is 2.2356 cents per kWh and the 2016 projected fuel cost is 3.2045 cents per kWh, which represents an increase of 0.9689 cents per kWh or 43.34%.

Q. What is Gulf's projected recoverable capacity payments for the 2016 cost recovery period?

A. The total recoverable capacity payments for the period are $85,539,016. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Boyett's testimony shows the projected cost associated with Southern Intercompany Interchange and lists the long-term purchased power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting cost. Also included in Gulf's 2016 projection of capacity cost is revenue produced by a market-based service agreement between the Southern electric system operating companies and South Carolina PSA. The total capacity cost of $88,202,632 is shown on Schedule CCE-4, line 13 in the exhibit to Witness Boyett's testimony. The total capacity cost included on Schedule CCE-4 line 13 is the sum of lines 1 and 2 of Schedule CCE-1.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments for the period?

A. No.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $128,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 3.

Q. How do the total projected net jurisdictional capacity payments for the 2016 period compare to the current estimated net jurisdictional capacity payments for the same period in 2015?

A. Gulf's 2016 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 6, are $85,495,331. This amount is $438,247 or 0.51% less than the current estimate of $85,933,578 (Schedule CCE-1B, line 6) for 2015 that was filed in Mr. Boyett's actual/estimated true-up testimony in this docket on August 4, 2015. The projected capacity payment decrease is the result of a decrease in Gulf's estimated PPA capacity payments offset somewhat by an increase in the estimated IIC payments for the period.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

BY MR. BADDERS:

Q Mr. Ball, have you prepared a summary of your testimony?

A Yes, I have just a brief summary. In direct testimony most of the issues have been stipulated to, and we do appreciate that.

The only issue remaining to be, I think, resolved under our direct testimony -- or my direct testimony is the matter of Gulf's filing of its 2016 Risk Management Plan, and more specifically in the plan just the section that deals with natural gas and the financial hedging of natural gas in Gulf's Risk Management Plan.

Gulf has filed Risk Management Plans almost identical to the one we filed for the 2016 period, 2014, 2015 plans. Those were virtually identical. They were reviewed and approved by the Commission. We feel like that the 2016 Risk Management Plan that Gulf has filed is a reasonable implementation of the plan that Gulf has to purchase natural gas and to financial hedge natural gas, and it's also, I believe, a prudent plan for complying with the Commission's hedging order. And as such, I feel like the plan should be considered for approval by the Commission.

MR. BADDERS: We tender him for

cross-examination.

CHAIRMAN GRAHAM: Thank you.

Mr. Ball, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: OPC.

EXAMINATION

BY MR. SAYLER:

Q Good morning, Mr. Ball. How are you today?

A Good.

Q From 2002 to 2014 your company incurred approximately $127 million in natural gas hedging losses; is that correct?

A That's correct.

Q And for 2015 your projected natural gas hedging losses are approximately how much?

A Approximately 44, and this is actual information we have through the end of September, and the amount that we included in our estimated/actual filing for the third -- for the fourth quarter of this year.

Q And between now and the third -- the end of the fourth quarter you expect it to remain about 44 million?

A Well, with prices falling as they have recently, it could be higher than that.

Q All right. Thank you. And you would agree that hedging costs or losses are borne by the customers alone; is that correct?

A That's correct. They are recovered through the fuel cost recovery clause.

Q You would agree that natural gas market conditions are different in 2015 from the market conditions in 2002 when the Commission started -- authorized utilities to hedge natural gas; is that correct?

A That's correct.

Q And you would agree that the advances in recovering gas from shale formations has increased the supply of available natural gas?

A That's correct.

Q And you would agree that the addition of shale gas into the market has also decreased the price of natural gas since 2002?

A It has in recent history. That's correct.

Q And the price of natural gas is lower now than it was in the mid-2000s; is that correct?

A That's correct, to the best of my knowledge.

Q All right. You would also agree that fuel price volatility is decreasing in general?

A Well, I guess it depends on what time period you're talking about. 2014, I wouldn't necessarily agree that fuel price volatility decreased in that year. And I'm not offering any opinion about future price volatility because I just have no idea as to what future price volatility in the natural gas market might be. But certainly overall, looking at the history from the start of the implementation of the Risk Management Plan, I'd say in the most recent history volatility has been lower.

Q All right. And you mentioned 2014. And a lot of that volatility was due to the Superstorm Sandy effect in February, early March of 2014, would you agree?

A No. I'm thinking it's more due to winter weather than the Sandy storm. But, you know, this is a risk that you run in the fuel price market. Events happen, weather being a significant driver of natural gas demand and, as a result, natural gas prices.

I think there's nothing that would indicate that these kind of weather events would not continue to occur in the future as well as they did in 2014.

Q So would you agree that there are a few trading days in February and then later on in March that drove most of the volatility for 2014?

A Yeah. That's probably a good summation of it, yes.

Q And if you were to take out those six or seven days then, fuel price volatility for '14 would be dramatically lower; correct?

A Well, I'm not --

Q Or lower.

A I haven't done a review of that, but I think in general terms I would agree.

Q All right. Thank you. And you would agree that your company doesn't estimate or forecast fuel price volatility for natural gas; correct?

A No. Our company does not forecast fuel price volatility.

Q By what objective standard or metrics do you measure the success or failure of your hedging program?

A We use a -- we do a calculation based on a standard deviation of fuel prices, both hedged and unhedged, and we produce that document in, I believe in our true-up testimony each year. And we also provide that information to staff's audit team when they do the hedging audit for Gulf.

But, you know, in general terms, Gulf uses financial swaps to hedge natural gas. Financial swaps are a tool that's used to basically have a fixed price contract for a certain quantity of natural gas. Fixed price contracts have no volatility, and so as you enter into fixed price contracts, just the nature of the program means that your volatility is going to be lower than a market price that changes every day.

Q All right. But your evaluation of the success or failure of your hedging program does not consider customer cost; is that correct?

A No, it does not. And the reason it does not is because the Commission has made it clear what the objective of the hedging order is, and that is price volatility.

Q All right.

A And that's how we measure the success of the program.

Q All right. Does the company make any profit or return on natural gas financial hedging transactions with its counterparties?

A No, it does not.

Q And does the company have any affiliate relationships with financial hedging counterparties?

A No.

Q And does the company have in place corporate policies and procedures for its employees, including officers, to prevent conflicts of interest as it relates to --

A Yes.

MR. SAYLER: All right. Thank you very much, Mr. Ball.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Mr. Wright?

MR. WRIGHT: No questions, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: I have some. Thank you.

EXAMINATION

BY MR. MOYLE:

Q Good morning. When was the last time that Gulf made any adjustments to its hedging plan?

A Gulf has a fairly active -- are you talking about the hedging Risk Management Plan?

Q Yes, sir. I mean, in your opening you said it's essentially the same.

A At least not for the last three years. They've been substantially the same. I can't remember when we made an adjustment. If we've made any, it's been small.

Q Okay. So I guess it would be fair to say a number of years since any adjustment has been made?

A That's correct.

Q And if an adjustment was made, it would be small. Can you describe the last adjustment that you remember being made?

A I can, I think, address this issue. And, you know, primarily what we've got is a Risk Management Plan that gives us -- gives Gulf quite a bit of flexibility in how we implement the plan. We have target ranges, and those ranges are fairly broad from year to year.

But outside of that, if we felt like the market conditions justify it, we can certainly go outside of those ranges. The only limitation that we have is that we will not hedge more than 100 percent of our projected gas burn for the year. So there's really no need to change the plan very much because we already have built in quite a bit of flexibility within the plan to adjust due to market conditions.

Q I mean, so I was just trying -- I appreciate the answer and we'll have a discussion. But with respect to your recollection of the last change, can you tell me -- do you recall it?

A The only change that I remember is maybe a small change to the target bands for each year that we have in the plan.

Q Okay. And are you able to tell us what that was?

A No. That's confidential information.

Q You could tell us but it would be confidential?

A That's correct.

Q Okay. I guess -- you heard the gentleman from Duke yesterday talk about what percentage they were hedging; is that right?

A I do recall that testimony somewhat, yes.

Q But you wouldn't be comfortable answering similar questions, or would you take the position that that's confidential?

A Are you talking about the hedging ranges that we have in our Risk Management Plan?

Q Yes.

A That is confidential information and I cannot answer that.

Q So you don't do like Duke where they go, okay, we want to do 60 percent. You have a different approach.

A That's correct.

Q And you have a range between X and Y, and X and Y are confidential numbers.

A That's correct.

Q Does -- do any of the other Southern Company -- Gulf is an affiliate of the Southern Company; correct?

A That's correct.

Q Do any of the other Southern Company affiliates hedge natural gas?

A Yes.

Q Who?

A As far as I know, all of them. They all have different programs because they all have different reporting relationships to commissions. But every one of them, to my knowledge, still engages in financial hedging of natural gas.

Q Do you talk to the people that are responsible for hedging with the other companies?

A Yes.

Q Okay. Does Florida have material differences in its hedging program compared to the other companies?

A Yes, it does.

Q What are they?

A Well, you know, I don't know all the details of each of the other operating companies' hedging plans, but I think a good example may be Georgia Power. Georgia Power's hedging plan is more directed by the Commission and particularly the Commission staff, and so I think the interaction between the staff and the hedging folks at Georgia are a lot more intertwined than they are here.

Q So when you say it's more directed by the Commission, I mean, does that contemplate regular and routine involvement by the Commission with respect to hedging?

A Yes, that's correct.

Q Does the Georgia Commission or the staff provide direction with respect to the --

A You know, I can't really go much further than that. That goes beyond my knowledge of their plan.

Q Okay. Let me ask you this. Does the Southern Company have unregulated affiliates that you know that engage in hedging?

A Yes. Southern Company does have an unregulated affiliate. And as far as I know, they do have a hedging program, but I am not familiar with it.

Q So if I asked you what the purpose -- what you understood the purpose to be of the hedging program related to the Southern Company unregulated affiliate, you wouldn't be able to give me an answer?

A I would not.

Q I just want to make sure I understood your response to a previous question with respect to the metric. Let me start, what's the objective of the Gulf hedging plan?

A It's --

Q What are the objectives? What are the goals?

A The objective of the plan is to limit volatility of natural gas price that we pay.

Q Okay. And I thought you said that the way you determine that is you look at the results at the end of the year, gains and losses; is that right?

A No. We do not look at gains and losses. We look at standard deviation of pricing, both hedged and unhedged, and we determine in each case that the volatility or the standard deviation of the hedged pricing for the year is lower than the standard deviation of the unhedged prices, thus basically making the case that we have reduced the volatility of pricing. But, again, we're entering into fixed price contracts which are not volatile. It's just a result of the program.

Q And a fixed price contract, just by definition, once you say I'm going to pay you X for this commodity, it's fixed, so you reduce volatility by entering into the contract; correct?

A That's correct.

Q And in hedging, as I understand it, it costs a lot more to enter into a fixed price contract for a longer duration of time as compared to a shorter duration of time. Is that your understanding with respect to the hedge because of the additional uncertainty associated with a three-year fixed price contract compared to a one-year fixed price contract, all other things being equal?

A Not necessarily for a swap contract. Swap contracts are initiated or executed at a future price, and typically that price is transparent, it's a NYMEX price. There is -- you know, you enter into the contract. So if I enter into a contract that settles three years from today, the contract price under the swap is very, very close to today's NYMEX price for that period.

Q Do you negotiate these hedges?

A I do not.

Q Does the company, or is it like something, you know, buying a Chick-fil-A sandwich where they won't negotiate with you on a hedge?

A No, it's not like buying a Chick-fil-A sandwich. I guarantee you that. I bought one this morning, and it's nothing like that.

(Laughter.)

We do have an organization within the fuel services organization at Southern Company. We have a financial hedging manager. I talked with him very frequently about Gulf's program. He is responsible for entering into these hedging deals on behalf of Gulf and the other operating companies within the Southern Company.

Q Okay. So it's done at the Southern Company level, not the Gulf level with respect to executing hedges; is that right?

A That's correct.

Q And do you know whether they're negotiated hedges or you just pay the NYMEX price?

A Every deal is negotiated to some extent. There are multiple counterparties that you can enter into agreements with, and all of them are contacted when we have a need to hedge. And we're always searching for the best price we can get in a hedge deal.

Q Right. Okay. And you had said you don't have an opinion regarding future price volatility. I assume your Southern Company people who actually execute the hedges that -- do you know, do they endeavor to try to peg future market volatility or do they rely on other services like EIA, I believe, to look at market volatility in the future?

A You know, we don't necessarily look at market price volatility. What we do do, though, is in our price forecasting we look at -- we look at not only the price forecasts that we'll use in projections, but we'll also forecast, you know, what are the bounds within confidence levels that the price could move within?

So we look at -- I think there's two standard ways of doing that. One is to look at historical volatility and determine confidence levels around that. The other is to look at the options market. And by taking the current options market, you can develop, you know, what's the probability that prices will fall within a certain bandwidth. And, you know, typically what you'll see as you go further out into the future, that band will get larger, which indicates more uncertainty further out into the future, which means more potential volatility. We don't have a way of determining exactly what we think the volatility will be. We just know that there's a possibility that price volatility will exist in the future.

Q Is the corollary that it just -- with respect to predicting the future, it's harder to predict something further out in time in the future than something closer in in time? You know, I use an example of the weather, that you have a better shot of getting it right on the weather prediction for tomorrow as compared to a week from tomorrow. Does that hold true in your opinion with respect to a market like natural gas?

A Yeah. I'd say generally I would agree with that, yes.

Q Okay. And what you described with respect to this, you don't do that. That's something that, again, that others do in terms of trying to project future pricing and volatility?

A That's correct. I do not do that.

Q Okay. Just a few more questions.

Gulf is engaging in some renewable energy projects; correct?

A That's correct.

Q Okay. And I have looked at some literature on hedging, and the literature has suggested that another way to hedge is to do other projects. If you wanted to hedge natural gas, you know, you could beef up on renewable energy projects. Does that concept -- do you have any familiarity with that concept that you potentially could hedge by looking at other energy sources for generating power?

A I'd say generally the answer to that would be yes, that any time that you can expand your generation mix, it provides you options to move generation from lower -- from maybe higher cost options to lower cost options. And particularly if you have a purchased power agreement where you've got a fixed energy price, it's very similar to a hedge because what we're searching for is like a -- you know, to reduce volatility. So if you've got a purchased power agreement that has a fixed price in it, that certainly reduces the volatility of your rates. And since we're recovering those through the fuel cost recovery clause, that does reduce volatility in the clause.

Q Do you take that into consideration? This Commission approved, I think, a wind project and a solar project for Gulf last year, maybe this year, but did you take that into account with respect to making any adjustments in your hedging plan?

A No, we did not, and primarily because the generating assets that burn natural gas at Gulf Power, at least in our forecast, are -- the burn on those units is not impacted by these projects.

Q If this Commission were to agree with the unified voice of the consumers to say please discontinue the hedging program, you would have some hedges that you've already executed in place; correct?

A That's correct.

Q Okay. Can you tell me how long -- how far out some -- like your longest hedges are? I mean, two, three years?

A More like five years.

Q Five years out? Okay. You would agree that those products have some value. They're assignable. To the extent that the Commission said stop and try to get the best you can for the instruments you've already executed as hedges, there may be other third parties who would have interest in picking up those hedges; is that correct?

A I'm not aware of any third parties that would be interested in taking these hedges on, no, I'm not.

Q Okay. So, but as an expert in hedging, isn't there a market that is transparent and viable for hedges, and you can buy and sell hedges in a market?

A Yes, absolutely there is. Not necessarily they would -- I mean, that market is available to everyone all the time. It doesn't necessarily mean that Gulf is a participant in the market of selling hedges. We're in the market of purchasing hedges.

Q I understand. But just to the extent that the Commission said, okay, we don't want you to continue to hedge, couldn't you take your hedge and either through a broker or somebody else and say here's a hedge we put in place for gas? In five years we're going to offload it and try to sell it. I mean, is that a foreign concept?

A It is to me. I'm not aware of doing that. Essentially what we would do would be to unwind the hedges that we have in place if that's the Commission order. We don't necessarily think that's something that we recommend doing.

Q How would you unwind them?

A Essentially you'd settle at today's market price with the counterparties that we have hedge deals with.

Q You'd settle them or sell them? I didn't hear you.

A We would settle them.

Q What does that mean?

A That means that every day there's a mark to market on the hedge positions, and they would be settled at that mark-to-market price. So you take the current forward market, the fixed price that we've negotiated under our swap agreements, and you would settle those agreements based on the, you know, the current forward market.

Q Okay. And just the last line of questioning. You would agree that the views of your customers are important to Gulf?

A Yes.

Q Okay. And you understand that the collective views of the representatives here, the Office of Public Counsel, the Retail Federation, and the Industrial Power

Users Group, is that hedging be discontinued; correct?

A I'm aware of that.

MR. MOYLE: Okay. Thank you for your time.

CHAIRMAN GRAHAM: Staff?

MS. BROWNLESS: Yes, sir.

EXAMINATION

BY MS. BROWNLESS:

Q Good morning, Mr. Ball.

A Good morning.

Q I would just like to follow up on Mr. Moyle's question so I can make sure I fully understand what you're saying with regard to what would happen if the Commission should tell you to discontinue hedging.

Now my understanding is that you have hedges in place today for various periods of time, 12 months, 24 months, 36 months, up to 60 months; is that correct?

A That's correct.

Q Okay. And if the Commission were to say as of December -- well, as of January 1, 2016, you won't hedge anymore, on January 1 would you execute the transaction you just indicated? In other words, for each and every one of those hedges would you go mark to market at that time and settle them up?

A No. We would not recommend doing that. That's -- if the Commission ordered us to, we would certainly do that.

Q Yes, sir.

A But we do not recommend it for -- really for two reasons. Number one is you would have all the IOUs in the State of Florida unwinding all their hedges at the same time. That would be a significant market event. And believe me, the financial counterparties would take advantage of that and they would extract as much financial gain as they possibly could because of that event.

Secondly, we have these hedges in place to mitigate price risk out in the future.

Q Right.

A So if you settle those hedges today, essentially what you do is you incur all the costs associated with the hedges, but you get none of the benefits in the future from potential future price volatility. There's really no reason to settle these hedges or unwind these hedges on January 1st of 2016.

The reasonable thing to do, in our opinion, is just to allow the hedges to naturally expire and naturally settle over the next five years.

Q As they were -- as the hedge was originally intended.

A That's correct.

Q Okay. And am I correct that in terms of trying to value a hedge that you really can't tell until you get to the date, the settlement date?

A That's correct.

Q On that settlement date either the market is higher than the hedge price or the market is lower than the hedge price?

A That's correct.

Q So on that date either it costs the customer more than the market or it costs the customer less than the market and, therefore, there was a savings?

A That's right. We would not know until the day that the hedges were settled.

MS. BROWNLESS: Okay. Thank you so much, sir.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Commissioners.

Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Mr. Chairman.

Yesterday I asked Duke a question. I think I did it inartfully, so I'll try again today.

So we have a framework over the past 12 years or so of how hedging -- how the hedging program has impacted customers or consumers by helping them ride the waves of tremendous cost swings, right, in the natural gas market, particularly thinking about 2004 to 2008 and before then. What information can you provide me to give me a clearer picture of how customers would have been impacted if hedging was not permitted? And specifically we're going to look at the 2004 to 2008 time frame and then 2009 to 2014 time frame. So if you can sort of give me a picture of how consumers would be impacted directly.

THE WITNESS: Well, first of all, let me just say, Mr. Commissioner, I haven't really done that analysis, so I'm -- all I can give you is just kind of a broad idea of what I think.

COMMISSIONER BRISÉ: Sure.

THE WITNESS: In that early period, there was quite a bit of volatility in the market, very high price spikes during that period of time. So if you were paying market price every day for natural gas that we purchased to run our generating plants, essentially the customer would bear that price. And while they wouldn't necessarily bear it during a month or several months, I would anticipate that there would at least be the possibility that we could have had midcourse corrections during that period to try to get the over- or under-recovery balance more in line.

But in any case, what the impact is going to be is that at the end of the year whatever under-recovery balance was remaining would be rolled into next year's rate. So the customer is going to see the impact of higher natural gas prices and price volatility in the following year's fuel cost recovery rate, and that would have been very significant in that early period you're looking at.

So in the later period, while there has been price volatility, we haven't really seen, other than maybe a brief period in 2014, very extreme runups in price. So in that period I think it's basically the same answer, although I think in our case we had some hedging -- with the exception of '14, which we did have a hedging gain -- in those years, we had -- most of those years we had hedging losses. So that would have basically been a credit to the customers' bill if they had not occurred in the current year.

So, you know, the customer is going to see the -- if you don't hedge, the customer sees the market price that we pay every day, and they will see that whether it's in the current year in the form of a midcourse correction or in the following year in the rates that we project for the following year, including the over- and under-recovery balance.

COMMISSIONER BRISÉ: You don't have any way to -- or you all haven't quantified the variances between those periods from year to year in terms of maybe -- from a percentage, not specifically a dollar amount, but a percentage of impact on, say, the customer for a year or a couple of years, over years.

THE WITNESS: I believe it could be calculated. I just don't know that -- I haven't done that analysis. I don't know that we, Gulf has, but certainly that kind of information can be generated.

COMMISSIONER BRISÉ: Okay. Because that would be helpful in the discussion from my perspective. So thank you.

CHAIRMAN GRAHAM: Mr. Ball, I have a question for you. You said that you personally do not do the hedging for Gulf; correct?

THE WITNESS: That's correct.

CHAIRMAN GRAHAM: Is it a Gulf employee that does the hedging or is it a southern employee that does the hedging?

THE WITNESS: It's a Southern Company Services employee, of which I am also a Southern Company Services employee. I work full-time for Gulf as their fuel manager, so essentially the fuel organization that I'm a member of, we also have a fuel -- a natural gas financial hedging manager that's part of our team, and he is the individual that enters into the hedge transactions.

CHAIRMAN GRAHAM: When the hedging is done, is the hedging done specifically for Gulf or is it done for Southern, and then later on they decide where they're going to apply that hedge to, which facility -- you know, they're going to say this hedge is going to go to Gulf, this is going to go to Georgia Power, this is going to go to such and such?

THE WITNESS: Yes. The hedging manager enters into the hedges specifically for each operating company. So it's not like a group hedge and then he allocates those hedges to each operating company. He actually goes and enters into hedge transactions specifically for Gulf Power Company and specifically for the other operating companies. Because everybody's program is different, the timing of the hedging activity is different. So it's all done separately.

CHAIRMAN GRAHAM: So it's done upfront. You know, when he's entering into the hedge, he knows this is for Gulf.

THE WITNESS: That's correct.

CHAIRMAN GRAHAM: Now have you, as far as you know -- as Mr. Moyle was asking you earlier about unwinding a hedge, have you gone into a hedge for Gulf and decided, well, we're going to, quote, unwind this and make it a Georgia Power hedge?

THE WITNESS: I'm sorry. I missed the question there. I apologize.

CHAIRMAN GRAHAM: If all the sudden you decide that it's just, it doesn't work appropriate for Gulf, we're going to associate it over with Georgia Power, have you done that before? Has Gulf done that before?

THE WITNESS: Just assign the hedges, Gulf's hedges to another operating company?

CHAIRMAN GRAHAM: Yes.

THE WITNESS: No. We couldn't -- due to the separation that we have to keep between operating companies because everybody is -- the Commission, of course, is looking to make sure that we don't have any cross-subsidization, I'm very confident that that kind of activity could not take place.

CHAIRMAN GRAHAM: Okay. Thank you.

Commissioner Brown.

COMMISSIONER BROWN: Thank you. I appreciate your testimony, Mr. Ball. Yesterday I asked one of

Duke's witnesses whether hedging has been revisited in the jurisdiction, other jurisdictions in which Duke operates. Similarly, Gulf operates in a multitude of states.

Has -- do you know if commissions have revisited the issue of the hedging programs that are in place in those jurisdictions that Southern operates in?

THE WITNESS: I do know that this has been an issue at other commissions, although I, you know, I'm not aware of any of the details of the discussions that go on there. Some jurisdictions look at it very frequently. I mentioned Georgia, but Georgia is a little bit different program and their, actually their staff is very heavily involved in directing the program. So they're, you know, they're looking -- they're -- commission oversight of their hedging program is basically ongoing.

The other jurisdictions, Mississippi Power and Alabama Power, I'm not aware of any specific action, but I do know that this is something that's looked at regularly.

COMMISSIONER BROWN: Okay. And really more has hedging been curtailed in any of those -- any of the programs been curtailed or cut back in those jurisdictions?

THE WITNESS: I'm not aware of where hedging programs have been eliminated in those jurisdictions, no.

COMMISSIONER BROWN: Thanks so much.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Redirect.

MR. BADDERS: No redirect. And we offer Exhibits 35 through 39 into the record.

CHAIRMAN GRAHAM: 35 through 39 we'll enter into the record.

(Exhibits 35 through 39 admitted into the record.)

OPC.

MR. SAYLER: Office of Public Counsel would like to offer Exhibit 117 into the record. And, Commissioner Brisé, you had had a question about midcourse corrections avoided. If you'll look at interrogatory response 50 and 51, Office of Public Counsel had asked that question.

CHAIRMAN GRAHAM: Any other exhibits?

(Exhibit 117 admitted into the record.)

Okay. Mr. Ball, thank you very much for your testimony.

Okay. I think it's a good time to take

a -- we'll call it a ten-minute break. So at 11:25 on the back -- that clock.

(Recess taken.)

Okay. We're all nice and refreshed. We're ready for the 90-minute sprint to lunchtime. So, TECO, your witness, please.

MR. BEASLEY: Thank you, Mr. Chairman. TECO calls Brent Caldwell.

Whereupon,

JAMES BRENT CALDWELL

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

EXAMINATION

BY MR. BEASLEY:

Q Mr. Caldwell, will you state your name for the record, please.

A Yes. My name is James Brent Caldwell.

Q Were you previously sworn yesterday to tell the truth in this proceeding?

A Yes.

Q Could you provide your business address, please.

A 702 North Franklin Street, Tampa, Florida 33602.

Q By whom are you employed and in what capacity?

A Tampa Electric Company. I am the Director of Fuel Planning and Services.

Q Mr. Caldwell, did you prepare and submit in this proceeding four sets of prepared direct testimony, the first one being 2014 hedging activity true-up testimony dated April 7, 2015; the second one being fuel procurement and wholesale power purchases Risk Management Plan dated August 4, 2015; the third one being natural gas hedging activities January through July 2015, filed August 14th; and the fourth one being testimony of J. Brent Caldwell, projections for January 2016 through December 2016?

A Yes, I did.

Q On the second one of those where the Risk Management Plan is identified as 2015, should that be corrected?

A Yes. The 2015 should be 2016.

Q With that change, if I were to ask you the questions contained in your four prepared direct testimonies, would your answers be the same?

A Yes, they would.

Q Have you reviewed the notice -- the document entitled Tampa Electric Company's notice of areas of witness expertise filed October 14 in this proceeding?

A I have.

Q In that it says that you're qualified as an expert witness in areas of regulatory policy considerations associated with natural gas financial hedging; the operation and result of Tampa Electric's natural gas financial hedging activities; the development, details, and execution of Tampa Electric's 2014 and 2015 and 2016 Risk Management Plans. Is it your intent to testify in this proceeding regarding those areas?

A Yes, it is.

MR. BEASLEY: We would offer Mr. Caldwell for any voir dire questions that the parties may have.

CHAIRMAN GRAHAM: Okay. Mr. Moyle, you realize that you are challenging a graduate of Georgia Tech? I just thought I'd tee it up for you.

MR. MOYLE: Mr. Chairman, I appreciate that because I was not going to ask him about his educational background.

(Laughter.)

VOIR DIRE EXAMINATION

BY MR. MOYLE:

Q I just have a couple of questions for you. Are you responsible for executing hedges for Tampa Electric?

A I do not personally execute the hedges, no.

Q Okay. Who does?

A The area of gas trading does the hedges, and I monitor and oversee and advise on the hedging. But we have -- due to separation of duties, we have very particular people that are allowed to do the hedging.

Q When you say separation of duties, what does that mean?

A Separation of duties is a -- it's kind of industry standard controls to make sure that whether you're talking physical gas or you're talking financial hedges, transactions are handled in an appropriate, responsible manner. People that do the deals are generally considered front office. The people that actually make the invoices happen, back office or settlements, those have to be completely different people, separation of duties.

Q Okay. And I'm familiar with some separation with respect to regulated companies and unregulated companies. Is that the separation you're talking about?

A It's not. I'm talking about the separation of duties in terms of executing and settling any sort of transaction.

Q Okay. In your -- the filing that was made that was just referenced by your company's lawyer, it talks about regulatory policy considerations. Are you comfortable talking about regulatory policy considerations if I ask you questions about that?

A I am.

Q Okay. So let me just test that a little bit. Can you tell me any cons related to hedging, any negative things related to hedging? If you were making a policy, if the Commission said, okay, can you give me the pros and cons or good and bad of hedging, if you got asked that question, would you identify any negatives?

A I mean, I could certainly address the potential outcomes of hedging and how those outcomes could be viewed as a con, yes.

Q Okay. Well, I'll ask you that when we talk.

MR. MOYLE: So given this man's education, I don't have an objection to his being qualified as an expert.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: Nor do we have any objection, no voir dire. Thank you.

CHAIRMAN GRAHAM: Okay.

MR. BEASLEY: Thank you, Mr. Chairman. At this time I would ask that the four sets of testimony previously identified by Mr. Caldwell be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Caldwell's, all of his direct testimony into the record as though read.

EXAMINATION

BY MR. BEASLEY:

Q Mr. Caldwell, did you also prepare what's been marked hearing Exhibits 50, 51, and 52 and submit them in this proceeding?

A Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 4/7/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Bulk Fuel and Power.

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

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric’s generating stations.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2011, and I testified before the Commission in Docket No. 120234-EI regarding the company’s fuel procurement for the Polk 2-5 Combined Cycle Conversion project

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission’s review, information regarding the 2014 results of Tampa Electric’s risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. ___ (JBC-1), entitled Tampa Electric’s 2014 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2014.

Q. What is the source of the data you present in your testimony in this proceeding?

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

Q. What were the results of Tampa Electric's risk management activities in 2014?

A. As outlined in Tampa Electric's 2014 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit customers' exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric’s gas needs have evolved and grown. All enhancements have been reviewed and approved by the company’s Risk Authorization Committee.

The report indicates that Tampa Electric’s 2014 hedging activities resulted in a net gain of approximately $15.6 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. Natural gas prices increased in early 2014 as a result of the significant inclement weather and resulting impact on coal deliveries and inventories during the winter of 2013/2014. Following that rise, the continuing abundance of natural gas supply from non-conventional, shale gas production has allowed natural gas prices to decrease again.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. No, Tampa Electric does not hedge natural gas pricing through physical gas supply contracts. Tampa Electric does hedge its natural gas supply through diversification. Tampa Electric also physically hedges its supply through the use of a variety of sources, delivery methods, inventory locations and contractual terms to enhance the company’s supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Additionally, Tampa Electric has storage capacity with Bay Gas Storage near Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric’s gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, until recently, Tampa Electric has used Sungard’s Nucleus Risk Management System (“Nucleus”). In 2013, Tampa Electric initiated a project to replace Nucleus with Allegro. The natural gas portion of the Allegro project replaced Nucleus for all natural gas financial and physical transactions effective November 1, 2014. Allegro supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. The Allegro system records all financial natural gas hedging transactions, and the system calculates risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2014?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2014.

Tampa Electric's generation comprises mostly coal and natural gas. The price of coal has historically been stable compared to the prices of oil and natural gas. In addition, there is not an organized, nor a liquid, market for financial hedging instruments for the high-sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility.

Tampa Electric consumes a small amount of oil; however, its low and erratic usage pattern makes price hedging impractical.

Similarly, Tampa Electric did not use financial hedges for wholesale power transactions because a liquid, published market does not exist for power in Florida.

Q. How does Tampa Electric assure physical supply of other commodities?

A. Tampa Electric assures sufficient physical supply of coal and oil through supply diversification, inventory sufficiency, and delivery flexibility. For coal, the company enters into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used in its electric generation system. Through a competitive bid process, supplier diversity and transportation flexibility, Tampa Electric is able to get competitive prices with valuable quality and transportation flexibility by selecting from a wide range of purchase options.

For oil, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season. Competition for potentially limited oil supplies and oil transportation during a crisis emphasizes the need for maintaining sufficient inventory.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Tampa Electric requests cost recovery pursuant to the Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI:

> Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 8/4/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Fuels Planning and Services.

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

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generating stations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. ____ (JBC-2), entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2016.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. ____ (JBC-2) provides Tampa Electric's overall plan for mitigating risk in the company's procurement of fuel and purchased power during 2016.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 08/14/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. ____ (JBC-3), entitled Tampa Electric Natural Gas Hedging Activities, January 1, 2015 through July 31, 2015.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. ____ (JBC-3) shows details of Tampa Electric's hedging activities for natural gas for the seven month period January through July 2015.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Fuel Planning and Services.

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generation plants.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2011 and Docket No. 130040-EI, and I testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes coal, natural gas, and oil. In 2015, as in previous years, coal is the fuel for

Big Bend Station; the Polk Unit 1 integrated gasification combined cycle utilizes coal as the primary fuel and natural gas as a secondary fuel; and Bayside Station combined cycles and the company’s collection of peakers (*i.e.*, simple cycle and aero derivative combustion turbines) utilize natural gas. Some of Tampa Electric’s peakers utilize oil as a secondary fuel. In 2015, the company expects total system generation to be 54 percent coal, 46 percent natural gas, and less than one percent oil.

During the upcoming year, Tampa Electric plans to test natural gas as a co-fired fuel in Big Bend station. The natural gas co-firing affects the system’s coal and natural gas consumption, as I describe later in my testimony. In 2016, coal-fired generation is expected to be approximately 48 percent of total generation and natural-gas fired generation, including the Big Bend co-fired volumes, is expected to be 52 percent. Generation from oil is expected to remain less than one percent of the total generation.

Q. Please describe Tampa Electric’s fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and lower costs for Tampa Electric's customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. Tampa Electric uses solid fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content and chlorine content. Since coal is not a homogenous product, fuel selection is based on unique characteristics, price, availability, deliverability, and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company’s coal procurement strategy to reflect current market conditions. Tampa Electric’s strategy provides a stable supply of reliable fuel sources while still allowing flexibility for the company to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric’s solid fuel, coal and petroleum coke supply for 2015.

A. Tampa Electric supplies Big Bend Station's coal needs through a combination of three coal supply agreements that continue through 2017 and a collection of shorter term contracts and spot purchases. These shorter term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2016 delivery?

A. Yes, Tampa Electric has contracted for approximately three-fourths of its 2016 expected coal needs through agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases or consumed from inventory during 2015 and 2016.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne delivery or rail delivery. Once delivered to Big Bend Station, Polk Unit 1 solid fuel is transported to Polk Station via trucks.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Transportation options provide benefits to customers. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal portfolio, 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2015 and 2016?

A. Yes. Tampa Electric expects to receive over one and one-half million tons of coal for use at Big Bend Station through the Big Bend rail facility during 2016.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive the balance of its solid fuel supply needs as waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River system through United Bulk Terminal or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Please summarize the company’s current coal waterborne transportation agreements.

A. In 2014, Tampa Electric issued Requests for Proposals (“RFP”) for all three legs of transportation for solid fuel originating from the Illinois Basin and delivered to Big Bend Station--river barges along the inland waterways, terminal service at the mouth of the Mississippi River, and transit across the Gulf of Mexico. Tampa Electric executed four new solid fuel transportation agreements with respondents to the RFP. The agreements were finalized in late 2014 and early 2015 and took effect in 2015.

Q. Please describe the four agreements.

A. For river barge transportation, Tampa Electric executed an agreement with Ingram Barge Company. This agreement provides river barge services from numerous docks on the inland waterway system to various terminals around New Orleans, Louisiana. The agreement expires at the end of [redacted] and provides annual transportation volumes between [redacted] tons and [redacted] tons. Tampa Electric also entered an agreement with an existing coal supplier, Knight Hawk Coal Company, to receive its supply delivered to the terminal. This effectively provides river transportation for [redacted] to [redacted] tons per year through [redacted]. The rates for these new contracts are approximately [redacted] to [redacted] per ton less than the previous river transportation agreement.

For terminal service, Tampa Electric entered an agreement with United Bulk Terminal. The agreement is through [redacted] with Tampa Electric having a unilateral right to extend the agreement through [redacted]. The new agreement provides over 500,000 tons of storage capacity, blending capability, no minimum throughput, discount opportunities and pricing flexibility. The new contract is priced approximately [redacted] to [redacted] per ton lower than the agreement that it replaced.

For Gulf transportation, Tampa Electric entered into an agreement with United Ocean Services through [redacted] with Tampa Electric's unilateral right to extend through [redacted]. The new agreement reduces the annual commitment from [redacted] tons to [redacted] tons. The cost to transport across the Gulf of Mexico also decreased by over [redacted] per ton.

Q. Please describe any other solid fuel transportation agreements that changed recently.

A. In 2014, Tampa Electric also issued an RFP for trucking service between Big Bend Station and Polk Station. The company entered an agreement with Dillon trucking to begin in 2015. Dillon subsequently agreed to start performing under the contract in late 2014 when Tampa Electric's previous truck transportation supplier found it difficult to perform as they began losing drivers when the contract with Tampa Electric neared expiration. The Dillon agreement continues through [redacted] at a fixed price, and Tampa Electric has the unilateral option to extend at a known price through [redacted]. The Dillon trucks are larger than the previous provider's trucks, thereby reducing volume of truck traffic at the stations and on the roadways. In addition, Dillon's trucks use compressed natural gas as fuel, providing cost savings and emission reductions. The price for trucking services under the Dillon agreement is slightly less than the prior agreement.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2016 solid fuel supply portfolio.

A. Tampa Electric placed an emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. There are several environmental regulations being enacted or proposed to be enacted in the next few years. These regulations will affect the types of coal, the quantities of coal that can be consumed at the stations or, most likely, both. Also, Tampa Electric and Florida’s generation assets continue to evolve. Tampa Electric is in the process of converting the natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined cycle unit. Several new natural gas combined cycle units recently have been built within the state. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary significantly each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Similar to its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. Such actions improve the reliability and cost effectiveness of the physical delivery of natural gas to the company’s power plants. Furthermore, Tampa Electric strives, on a daily basis, to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric’s risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric’s diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission (“FGT”) and Gulfstream Natural Gas System, LLC (“Gulfstream”) pipelines. The ability to deliver natural gas directly from two pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero-derivative combustion turbine and coal unit startup. Polk Station receives natural gas from FGT to support the four natural gas combustion turbines at that station.

Q. What actions has Tampa Electric taken to enhance the reliability of its natural gas transportation portfolio?

A. In 2015, Tampa Electric acquired 20,000 MMBtu per day of firm FGT FTS-3 capacity at the discounted rate of [redacted] per MMBtu. The quantity grows to a maximum of [redacted] MMBtu per day by [redacted] and remains at that level through the [redacted] year term of the agreement.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. Currently the company reserves 1,250,000 MMBtu of long-term storage capacity and has 250,000 MMBtu of shorter-term storage capacity.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT

Zones 1, 2 and 3. Diverse receipt points reduce the company’s vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header (“SESH”) and the Transco lateral. SESH and the Transco lateral connect the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase. Thus, SESH and the Transco lateral give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Does Tampa Electric have plans to secure additional natural gas supply for 2016 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately two-thirds of the company’s expected natural gas requirements for 2016. The balance of Tampa Electric’s natural gas supply will be acquired through seasonal, monthly and daily purchases to meet its varying operational needs.

Q. Will Tampa Electric’s generating stations require a greater volume of natural gas in 2016 compared to expected usage during 2015?

A. Yes, the company expects to use additional natural gas at its Big Bend Station. During 2015, the company has been converting the igniters on the coal-fired Big Bend Units 1 through 4 to run on natural gas instead of oil. This work is expected to be completed in October 2015. In 2016, Tampa Electric plans to test the co-firing capabilities of the units. Co-firing, using natural gas to supplement the coal-fueled input of the four coal units, will allow the company to respond quickly to operational changes, environmental constraints, and shifting customer demand. Co-firing is also expected to increase the reliability of these units’ operation.

Q. Will Tampa Electric need to enter additional supply or transportation contracts for the natural gas to be used at Big Bend Station?

A. In isolation, no, Tampa Electric does not need to add additional supply or transportation contracts for the natural gas to be consumed at Big Bend Station in 2016, particularly since the gas is for testing purposes and for startup. However, the FGT FTS-3 pipeline capacity added in 2015 is needed to account for the cumulative demand from Big Bend start-up, potential restrictions on coal-fired generation from environmental regulations associated with the Clean Power Plan, increased operational limits proposed by interstate pipelines, and overall competition for gas supply and pipeline capacity for delivery to the surging natural gas-fueled generation market in Florida.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2016 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences. Tampa Electric utilized the average of the five daily NYMEX natural gas futures settlement prices for the period April 30, 2015 – May 4, 2015 to prepare the fuel price forecast.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2016 projected fuel prices compare to the fuel prices projected for 2015?

A. Fuel prices for coal and natural gas for 2016 are projected to be lower than the prices projected for 2015. Continued natural gas production from shale reserves coupled with low crude oil prices is pushing prices down for all fuel commodities. Natural gas prices are projected to be slightly higher in 2016 than the natural gas prices projected for 2015 in the company's actual-estimated analysis. The lower coal demand resulting from coal-fired unit closures is expected to keep coal prices low despite some consolidation and production cuts in domestic coal supply.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. While 2016 projected prices for coal and natural gas are expected to be similar to 2015 prices, Tampa Electric recognizes that there is uncertainty in future prices. Therefore, Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 35 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by

20 percent. Due to Tampa Electric's generating mix and Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on August 4, 2015 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2015 and 2016 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2015 natural gas supply needs and a portion of its expected 2016 natural gas supply needs in accordance with the company's hedge plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 14, 2015.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2015 and 2016 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are also described in detail in Tampa Electric's Risk Management Plan.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the volume of natural gas expected to be consumed in its power plants. The volume hedged is driven by the projected total natural gas consumption in its combined-cycle plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee and monitored by the Risk Management department. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2015 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the Risk Management Plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 7, 2015, the company filed its 2014 Natural Gas Hedging Activities report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2015, in this docket on August 14, 2015.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. Tampa Electric's hedged quantity of natural gas may or may not generate a fuel savings. Fuel savings is not the focus of the hedge program. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission, not speculate on the price of fuel. Tampa Electric's hedging program requires consistent hedging based on expected needs. The company does not engage in speculative hedging strategies aimed at out-guessing the market. This discipline ensures the needed hedge volumes will be in place for customers regardless of the price movements of natural gas.

Hedging Issues

Q. Have you reviewed the issues raised by OPC regarding the appropriateness of financial hedging?

A. Yes, I have. I believe the following two uncontested issues have been raised by OPC:

One, is it in the consumers' best interest for the utilities to continue financial hedging activities?

And two, what changes, if any, should be made to the manner in which electric utilities conduct their financial hedging activities?

Tampa Electric will await and review the interveners' positions stated in testimony, due September 23, 2015, prior to the company formulating a response. However, statements by the Commission in its orders addressing financial hedging and hedging audits by the Commission's Staff suggest that utilities hedge using systematic and prudent methods, consumers benefit from the utilities' financial hedging activities, and no changes need to be made to the manner in which electric utilities conduct their financial hedging activities.

Q. Please identify the orders and audit results to which you refer.

A. In 2002 the Commission issued an order[1] ("the Hedging Order") approving a proposed resolution of issues relating to financial hedging, between and among Florida

[1] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI

Power & Light ("FPL"), Duke Energy Florida's "DEF" predecessor, Gulf Power, Tampa Electric, OPC and FIPUG. The Hedging Order established a framework and direction for the Commission and the parties to follow with respect to risk management for fuel procurement. That framework, with some later modifications, constitutes the risk management policy and procedures the Commission follows today. In the Hedging Order, the Commission noted that the resolution it approved appeared to remove disincentives that may have existed for IOUs to engage in financial hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred financial hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.

Order No. PSC-08-0316-PAA-EI[2] was the first of two clarifications in 2008 to the Hedging Order. This Order established a requirement that each IOU file a current-year, financial hedging review (Hedging Information Report) that provides actual hedging information for the period August 1 through July 31. The reporting requirement was established to enhance the Commission's

[2] Order No. PSC-08-0316-PAA-EI, issued May 14, 2008 in Docket No. 080001-EI

tools for reviewing the prudence of the utilities' most recent financial hedging activities.

The Commission then entered Order No. PSC-08-0667-PAA-EI[3], in which it affirmed its long-term support for financial hedging. In reviewing FPL's guidelines for financial hedging, the Commission noted that hedging can reduce the volatility of fuel adjustment charges paid by customers and that a well-managed financial hedging program does not involve speculation. The Commission further noted that in the 2008 mid-course corrections for DEF, FPL and Gulf, hedging gains significantly reduced the projected under-recoveries. The Commission said that it had previously found that customers benefit from stable rates that allow the customers to budget for electric bills and hedging has contributed to the stability of fuel factors.

In its ruling in Order No. PSC-08-0667-PAA-EI, the Commission stated that by approving FPL's proposed guidelines, "we demonstrate our support for hedging." The Commission further stated:

> “We find that utility hedging programs provide benefits to customers. By approving these guidelines we provide

[3] Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No. 080001-EI

regulatory support and guidance regarding hedging programs.”

The benefits of hedging were highlighted in a management audit conducted by the Commission's Staff in 2008. Upon completion of the Staff's audits of IOU hedging activities, the management audit concluded:

Overall, audit staff believes that the use of financial hedges for fuel purchases provides a benefit to utility customers. Each program is appropriately controlled, efficiently organized, and operates under a non-speculative format. There are areas of improvement, which are outlined later in each company's chapter. Generally, each company has successfully mitigated the price volatility for its customers. There have been years in which each company's hedging program provided a gain on its fuel cost, and years in which each program has incurred losses. This is to be expected. Hedging commodities involves the risk of higher prices at the expense of attempting to reduce price volatility. For each company, there is an acceptable level of risk tolerance between the two. Each utility must continue to gauge its customers' tolerance of the cost associated with hedging versus the benefits of reduced fuel cost volatility and any resulting rate increases.

Through its initial approval of the proposed resolutions in 2001 and later, through subsequent orders clarifying the Commission view on Hedging, the Commission and its staff have recognized the benefits of financial hedging and the impact on the utilities' customers. Additionally, the Commission has carefully monitored and evaluated the conduct of each IOU's financial hedging activities with no noted suggestion of imprudence. Tampa Electric will address any points raised by intervenor witnesses regarding whether or not financial hedging should continue in its present form or be modified in future rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Okay. Would you please summarize your direct testimony?

A Good morning, Commissioners. My name is James Brent Caldwell, and I'm the Director of Fuel Planning and Services for Tampa Electric Company. I have over 15 years of experience in fuel procurement and hedging activities. I sponsored testimony in these subjects in which most of the items have been stipulated. I'm here today to address the remaining hedging issues in this docket, including approval of Tampa Electric's 2016 Risk Management Plan.

Tampa Electric's Risk Management Plan describes the company's strategies to mitigate fuel price volatility using a disciplined, non-speculative approach that includes financial hedges for natural gas. These financial hedges are entered solely for the benefit of customers. This concludes my summary.

MR. BEASLEY: Thank you. We tender Mr. Caldwell for cross-examination.

CHAIRMAN GRAHAM: Thank you.

Mr. Caldwell, welcome.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: OPC.

MR. SAYLER: Thank you, Mr. Chairman.

EXAMINATION

BY MR. SAYLER:

Q Good morning, Mr. Caldwell. How are you today?

A Doing well. Thank you.

Q All right. From a -- you've heard me ask the other utilities this, so I'm sure you know where I'm going. From 2002 to 2014 your company incurred approximately $381 million in natural gas hedging costs or losses?

A Yes, I agree.

Q All right. And for 2015 your company is projected to incur approximately 23 million in natural gas hedging costs or losses?

A I think an updated number would be closer to $40 million, but, yes.

Q To 40 million. Okay. And is that actual through September?

A That's really actual through October with estimates for November and December.

Q Okay. And you would agree that hedging costs or losses are solely borne by the customers; is that correct?

A Yes. As is the benefit.

Q All right. And without the cost of hedging, customers would have kept approximately a little over $400 million in their pockets; is that correct?

A Yes. But would not have had the protection from potential price spikes.

Q Okay. And you would agree that natural gas market conditions are different in 2015 from the conditions in 2002; is that correct?

A Yes. One of the joys of the natural gas market is the conditions are changing every day.

Q And you would agree that advances in recovering gas from shale formations has increased the supply available -- of available natural gas since 2002?

A Yes. The natural gas market seems to go in cycles. You'll get a big production increase, then demand will come to match that, then a different source will be found, whether it's LNG, whether it's the deep water Gulf of Mexico. Supply and demand are always running to catch up with each other.

Q All right. But the answer to the question is has advances in shale gas -- recovering gas from shale formations increased that supply, and the answer is yes; correct?

A Yes.

Q Okay. And you would agree that shale gas being introduced in the market has also decreased the price of natural gas since 2002?

A Increase in supply, reduction in demand. The current -- the current excess supply has prices depressed a little bit, yes.

Q All right. And you would agree that fuel price volatility is decreasing, say, for the period 1997 to 2015?

A Overall, yes. It certainly has not been eliminated.

Q And you would agree your company does not estimate or forecast fuel price volatility for the price of natural gas; is that correct?

A I agree.

Q Does your company make any profit or return on natural gas financial hedging transactions entered into between the company and its counterparties?

A We do not.

Q Does the company have any affiliate relationships with its financial hedging counterparties?

A We do not.

Q With the recent announced sale of Tampa Electric to -- I can't remember the name of the company in Canada.

A Emera.

Q Yeah, Emera. Has anything changed in that affiliate relationship as is relates to affiliate relationships related to counterparties?

A No.

Q Okay.

A That deal has not closed.

Q Okay. But assuming it closes, it wouldn't cause an affiliate counterparty relationship?

A Not that I'm aware of.

Q Okay. And does the company have in place corporate policies and procedures for its employees, including officers, to prevent conflicts of interest as it relates to financial hedging transactions?

A Yes.

Q All right. Thank you very much, sir.

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: No questions, Mr. Chairman. Thank you.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

EXAMINATION

BY MR. MOYLE:

Q Mr. Caldwell, tell me what the cons are with respect to hedging.

A Well, certainly when the market price closes below the hedge price, that differential, that opportunity (phonetic) cost, that loss can be viewed as a con. The reality is it's the offset to the price of -- the market price of gas, the physical cost went down compared to what that hedge price was, so ultimately the combination of the reduced physical cost plus that loss is actually the price that was agreed to at the previous time. It's just the fixed cost. So the loss would be viewed as a con, but the benefit was there was a known certainty to that price at that time.

Other potential cons, there is an administrative burden for reporting hedges where they're doing the mark to market, you're doing the extra transactions for settling them, and all the controls are in place associated with entering the hedges. So that's a con as well.

Q Okay. Anything else?

A Nothing that comes to mind.

Q Okay. Then give me the pros.

A Well, the primary pro would be uncertainty. I'm a fuel planner, so having a good plan for what you need and when you need it is important. Uncertainty generates costs, unprepared for and uncontrolled costs.

Hedging, the pro there is you're set, you know what your price is going to be some point in the future and you can plan around that price. You can set your fuel factor appropriately, and that price you're setting is what the market was at the time that deal was entered. So the pro is certainly that increased certainty.

Q Did you suggest that uncertainty generates cost? I didn't -- did you say that?

A I did. Uncertainty can generate cost.

Q But not necessarily; right?

A Not necessarily.

Q And with respect to one of the pros, you know, reducing volatility, you'd agree that that's kind of what the Commission has said is the chief objective of hedging; correct?

A Yes. And certainly volatility is a form of uncertainty.

Q Right. And let me get away from the energy field, but, you know, I think the market price, generally speaking, I could be off a little bit, of a Honda Odyssey is probably $35,000 to $40,000. If I said, well, I don't know what the sticker price is going to be, it might go up or down, you know, I want to execute a hedge for $80,000 for a Honda Odyssey next year, as an expert you wouldn't advise that that kind of hedge be executed, would you, given the price disparity between what something costs now and what I would be executing a hedge for? You know, that would eliminate uncertainty and say, hey, I know I can get one of these for 80 grand next year. You wouldn't advise me to do that, would you?

A As you put that scenario together, no.

Q But doesn't hedging in effect require those types of analysis or judgments in your opinion?

A No, I don't believe so.

Q And that's because your plan -- you hedge regardless of price, regardless of market price. Your plan says here's what we do, here's what we go in, here's how much we buy percentage-wise, timing-wise. There's no subjectivity in your hedging plan; is that right?

A Correct. We are hedging price agnostic.

Q Are you agnostic to hedging?

A No. We believe hedging provides benefit to customers through providing stable prices, more stable, more certain prices.

Q Notwithstanding that all the customers are saying we don't really see much of a benefit given that we've had, over the life of hedging with Tampa Electric, 281 million in losses?

A We certainly consider our customers' concerns. Overall, the way I look at it, those losses, as you refer to them, reflect a decreased price in natural gas. Customers benefited in the unhedged portion but benefited in the overall less energy cost.

In isolation, the $381 million, $400 million looks bad, but the reduced cost of natural gas is the overall benefit. And certainly during that time there's been the protection from the potential for price spikes.

Q Yeah. So let's make sure we have our numbers right. You told Public Counsel that the updated number for the annual loss was 40 million; is that right?

A For 2015 estimate, yes.

Q For 2015; right?

A Correct.

Q Okay. So did you adjust the 381 million to take into account this 40 million?

A I believe the 381 is through 2014. If you add the 40 million for 2015, that would be about 420 million.

Q And so you would agree, just to make sure the record is clear, since the inception of hedging for Tampa Electric in a dollars and cents basis the customers have lost 420 million; is that correct?

A The opportunity cost, the reduction, the hedging loss, yes, is 420 million.

Q And do you have a projection as to how customers are going to do in '16?

A We do a mark to market every month. We close out at -- I'm not sure exactly what that number is. At the time of the filing of the Risk Management Plan I believe it was around $15 million.

Q How much?

A Fifteen.

Q Fifteen to the good or bad for customers?

A A loss.

Q And if the Commission said, you know, we've kind of heard a lot about hedging and we don't want it to continue, that 15 million is kind of locked in. I mean, they couldn't take action that would affect that one way or the other for '16?

A Well, '15 is not locked in at all. That's the current mark-to-market estimate. If prices go up, some sort of event, extreme weather, geopolitical turmoil, some sort of regulation on fracking, that loss, that mark to market could certainly become a gain.

Q Okay. And the events you identified are all pretty significant events; correct?

A They are.

Q Yeah.

A But certainly not uncommon events.

Q So a couple of questions about unwinding. You know, if the Commission said we're going to discontinue the hedging practice -- if you go buy a hedge today and you pay $100 for it and then the Commission today verbally said we don't want to do this anymore, please take action to unwind, that hedge would still have value tomorrow in the market presumably; right?

A It depends on how the market moved from the time you executed the hedge and the point where you unwind it.

Q Right. So but in a day, I mean, what do you typically see the market move in a day? Pennies?

A Are we talking natural gas pricing?

Q Yes. Yes, sir.

A Natural gas pricing can easily move 25, 50 cents in a day. And at a $2 price, that's the neighborhood of, what, 10, 20, 20 percent. So, I mean, on a day-to-day basis natural gas prices can move a lot.

Q Right. Okay. But, again, I just want to understand, you know, even in a worst-case scenario, 20 percent, you bought it for 100 then you sell it for 80, it would still have some value.

A Yes. You'd still have the market value, but you would effectively lock in that $20 loss that you're alluding to, and you've given up the protection that prices could go above 100.

Q Sure. And it could go the other way too; right? I mean, the 20 percent change could go higher or lower. It's just you don't know what the market is going to do.

A Agreed.

Q All right. And if an unwinding were to take place and you were going to give a recommendation, a hedging policy recommendation to this Commission, wouldn't you recommend that the unwind period not be January 1 and have one day where everybody is putting hedges into the market, but that you all use business judgment over a year or 18-month time period to unwind your hedges over time and in smaller increments?

A I very much agree with you would not want to unwind everything at one time as the previous witness alluded to. That much selling into the market could certainly deflate the price.

In terms of how best to unwind, obviously we would follow the Commission's direction on that, but I do believe allowing the hedges to expire naturally would be the best way to balance the protection of customers from price spikes and letting the existing policies run their course.

Q How long in the future do y'all hedge?

A Twenty-four months.

Q Do you hedge coal?

A We buy coal at fixed prices, but we do not do financial transactions to hedge the price of coal.

Q What percent of your generation fleet is coal?

A It varies year to year, between 40 and 60 percent. Sometimes gas is more, sometimes coal is more.

Q So you have two supply -- what is natural gas? What percentage is that?

A What percentage is natural gas of our generation?

Q Yes, sir.

A Approximately 50 percent.

Q Fifty? So is it fair to say roughly coal is approximately half and natural gas is approximately half?

A Correct. Yes.

Q No financial hedges on coal but financial hedges on natural gas?

A Correct. I mean, fixed price --

Q Coal markets move as well; correct?

A They do.

Q Yeah. Okay. With respect, and I asked other utility witnesses this question in terms of measuring whether the objective of reducing volatility has been successful, do you have a way in which you judge whether reducing volatility, you know, has been successful or not?

A Yes. There's kind of two pieces there. The first is we've designed a plan that by locking in known prices a little bit at a time spread out over a period, by definition that's going to reduce volatility.

And then the second way is we do periodically -- as we're preparing for the next filings, we are monitoring the standard deviation and observing that that -- that the hedge prices are -- have a lower standard deviation than the market prices.

Q What does that mean? Tell me about the standard deviation. From my perspective, I'll tell you I understand, like, the dollars and cents a lot better than I do standard deviation, but that may be just my educational background. So if you would explain that to me, please.

A Sure. Standard deviation is kind of a measure of the spread of a distribution, a collection of values, and the greater the standard deviation, the wider that spread is relative to the average, the mean. So a smaller standard deviation means less variation.

Q Okay. And have you done any analysis that -- I mean, I think we understand the dollar analysis, that if you measure the success of hedging on a dollar analysis, there's been, you would agree, significant losses to the customers associated with Tampa Electric's hedging program since inception; correct?

A A lot of costs offset by the benefit of protection from price spikes and volatility.

Q Right. But the 400 million, you're not contending that's an insignificant sum of money.

A No, I'm not.

Q Yeah. It is a significant sum of money; correct?

A Sure. Relative to a lot of money for fuel costs over that time.

Q Do you know what percent that would be?

A I believe it's right about 4 percent. So about $10 billion in fuel and purchased power costs over that same time period.

Q Does Peoples Gas hedge?

A Yes.

Q Do you -- have you looked at their hedging plan as compared to yours?

A I have.

Q Do they hedge more or less?

A I believe the plan is virtually identical.

Q And they're 100 percent gas; right?

A Yes.

Q Would that suggest maybe you're over hedged? I mean, if their whole fuel source is gas and they hedge the same as you do and you have 50 percent gas and you hedge the same amount, could somebody say, well, wait a minute, you guys are hedging too much?

A I don't see that connection. We use the -- we use the same percentage bounds, minimum and maximum, relative to the expected gas consumption.

Q Can you tell me what those are, the minimum and max?

A I believe those are confidential.

Q Are you comfortable telling me whether the 60 percent number that Duke used, whether your range -- that would be within your range?

A It's in the ball park, yes.

Q Okay. Just a few more questions, if I could.

You agree that renewable energy is also -- can be viewed as a hedge; correct?

A It can be, yes.

Q And you all have announced some renewable energy projects; correct?

A We have.

Q Have you factored that in into making any adjustments to your hedging plan?

A To the extent that the renewable energy would reduce the natural gas consumption, then the amount would be the same percentage, but the absolute quantity of natural gas hedged would decrease.

Q Because it would reduce your generation mix?

A Correct.

Q And when's the last time you made a change to your hedging plan?

A I don't remember precisely, but I do believe it was between 2008 when there was the big PSC audit on hedging, the big review, and then before the 2011 hedging review associated with FPL's VMM filing, and it was in that time frame.

Q Do you remember what the change was?

A I do. We went from an 18-month hedge plan to 24-month.

Q Do you know why you made that change?

A The intent to provide a little more stability, a little more certainty in pricing. When you're filing your plan in September, the 24 months helps cover the period roughly that you're planning around.

Q Is it more expensive, all other things being equal, to buy a hedge further out in time?

A Not necessarily. We're buying swaps. And ultimately what a swap is, there's someone that's selling natural gas out there and there's someone that's buying natural gas, and it's the price that both of them are willing to trade at that future date.

Q You're aware that other commissions around the country are looking at hedging as we speak?

A Yes.

Q Okay. And you're aware that some commissions have discontinued hedging?

A I've heard that, yes.

Q And you're aware -- do you have any personal knowledge about the Georgia commission and how the staff is involved in the hedging operations in Georgia?

A Not at all.

Q Other than what you just heard from the previous witness?

A Right.

Q And you rely on others to make forecasts for gas prices in the future; right? You're not putting together your own gas forecast.

A Ultimately my area does prepare the long-term natural gas price forecast, but we base it on publicly available industry standard forecasts.

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

CHAIRMAN GRAHAM: Staff?

EXAMINATION

BY MS. BROWNLESS:

Q I just have one question, sir. With regard to if the Commission should determine that hedging should be stopped, is it your opinion that trying to sell the hedges that you have currently in place is a less desirable option than letting them automatically work out?

A Yes.

Q And is that because if you sell them, you may or may not realize a profit on that hedge, but if you let them work out, the customers may get the benefit of a higher spot price when the hedge settles than -- in other words, the customers have the potential to get a benefit if you keep the hedge. They have no potential to get a benefit if you sell it.

A Yes, I would agree with that.

Q Thank you.

A The additional piece is if everyone in Florida is unwinding hedges at the same time, you've got some financial impact to the market. Prices would go down and you would actually recover less value than the hedges might be worth otherwise.

MS. BROWNLESS: Thank you so much.

CHAIRMAN GRAHAM: Commissioners? Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you. Just to be fair to you, we have a framework over the past 12 years or so of how the hedge program has impacted consumers or customers by helping them ride the waves of tremendous cost swings in the natural gas market. What information can you provide to give me a clear picture of how customers would have been impacted if hedging was not permitted, specifically after the spikes in costs between 2004 and 2008, and then contrast that to 2009 to 2014? And if you can be as specific as possible in terms of impact to consumers, that would be helpful.

THE WITNESS: I don't have any numbers and calculations to back this up, but no doubt 2004 through 2008 there were very significant price spikes, 2008 being one that comes very much to mind.

We did not file a midcourse correction in 2008, and I believe a big portion of that was because we had hedges in place. My suspicion is if we had filed a midcourse correction, if customers had seen that spike, there would be more calls to our call center, more calls to Public Counsel, more calls to the Commission in the 2004 to 2008 time frame. That's where gas is moving from, let's say, a $6 base and spiked up to 14, 15, I've seen 18 and so on, so that was a roughly doubling.

Since 2008, prices certainly have come down. The significant economic impact of 2007, 2008, 2009 reduced demand. At the same time we had significant growth in supply, so an unusually large abundance of natural gas in the last couple of years.

Personally I'm hoping that continues. It's good for consumers to have abundant natural gas. But the possibility of prices being, say, 2.50, I heard that number used as the 2015 strip (phonetic), the chance of prices going to $5 seems very reasonable. When you look back, it was $5 not very long ago. Could it go to 7.50? That's very possible as well. So, you know, you get a 2.50 move and the price will double. So, like, we set our fuel factor on 2.50 next year, well, then it goes to $5, a 2.50 jump, not small. Small compared to 2008 but big in terms of customer impact. It's going to double the cost of gas in the fuel clause.

So, you know, bottom line, we've enjoyed lower prices for the last couple years with this abundant shale gas, and I'm hoping that continues, but I still believe there is significant risk to the upside in prices going forward.

COMMISSIONER BRISÉ: Thank you.

CHAIRMAN GRAHAM: Mr. Caldwell, I have a question for you. In your summary, you said that hedging is solely for the benefit of the consumer. So you're saying that the utility gets absolutely zero benefit from hedging.

THE WITNESS: Zero is probably not the right term. I believe providing customers protection from potential spikes in natural gas is a benefit to customers, and the utility gets the associated benefit of customers not calling to complain about I can't pay for my bill. So there is a benefit to the utility.

There's also an awful lot of potential risk. When there are losses everyone wants to know why. When there are gains maybe you don't hear as much.

And there are administrative costs. I mean, there's plenty of reports, plenty of financial analysis, accounting that's done to make sure the hedges are within the Risk Management Plan and to make sure that they're settled accurately. So, I mean, there is an administrative cost that the utility bears. But overall the benefit to hedging is stable prices for customers.

CHAIRMAN GRAHAM: But the certainty that you spoke of earlier, there's no benefit to certainty for the utility?

THE WITNESS: To the extent that we forecast the fuel factor for next year and the value is set at that and then the costs come in in line with that level, meaning generation matched, fuel cost matched, load was the same, everyone benefits. You have small under-recoveries or small over-recoveries, you're not having to do midcourse corrections, you're not having to carry that cost. When you have your revenue matching your costs, that is kind of the best for the utility, no doubt about it.

CHAIRMAN GRAHAM: So basically there's no financial benefit to the utilities over-hedging, but there is side benefits or tangential benefits that come because of hedging.

THE WITNESS: I agree.

CHAIRMAN GRAHAM: Okay. Commissioner Brisé.

COMMISSIONER BRISÉ: So just to follow up on Chairman Graham's question, so if there are no financial benefits to the utilities with the hedging program and the consumers are saying, look, get rid of the program, what's the interest that the utilities have in ensuring that from a policy perspective that hedging continues to exist?

THE WITNESS: Well, it gets back to that kind of scenario I alluded to. Certainly when prices have spiked and the utilities have come in for large under-recoveries, it's a combination of customers calling because they can't pay their bill, customers calling and complaining about the big jump in the fuel factor -- it really is that -- and it's sometimes what we use, but it is that premium, that protection insurance payment, and the utility does get that benefit of knowing customers aren't going to have to experience those significant price spikes.

Customers, utilities have had the benefit of the last several years of those price spikes have not materialized significantly other than '14. But we do believe there's risk still out there, and providing that protection for customers is a tangential benefit.

CHAIRMAN GRAHAM: Redirect?

MR. BEASLEY: Mr. Chairman, we have no redirect. I would ask that Mr. Caldwell be excused until he comes up again.

CHAIRMAN GRAHAM: Okay.

MR. BEASLEY: Move Exhibits 50, 51, 52.

CHAIRMAN GRAHAM: 50, 51, and 52?

MR. BEASLEY: Yes, sir.

CHAIRMAN GRAHAM: Okay. OPC.

MR. SAYLER: Public Counsel would like to move Exhibit 118, which is a collection of interrogatory responses. And we had asked a similar question on interrogatory No. 31 to your question, Chairman Graham.

CHAIRMAN GRAHAM: Okay. Any other exhibits?

(Exhibits 50, 51, 52, and 118 admitted into the record.)

All right. Mr. Caldwell, thank you very much for your testimony today.

OPC, I think it's time for your first witness.

MR. SAYLER: Yes, sir. Mr. Chairman, Office of Public Counsel would like to invite Mr. Tarik Noriega to the stand.

Whereupon,

TARIK NORIEGA

was called as a witness on behalf of the Citizens of the State of Florida and, having been duly sworn, testified as follows:

EXAMINATION

BY MR. SAYLER:

Q Mr. Noriega, you were here yesterday when all the witnesses were sworn; is that correct?

A Yes, it is.

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

A My name is Tarik Noriega. My business address is 111 West Madison Street, Suite 812, Tallahassee, Florida 32399.

Q By whom are you employed and in what capacity?

A I'm employed by the Office of Public Counsel, OPC, as a Legislative Analyst.

Q Okay. And you did prepare and submit direct testimony in this proceeding?

A Yes, I did.

Q And do you have that testimony before you?

A Yes, I do.

Q And do you have any corrections or revisions to make to your prefiled direct testimony?

A Yes. Thank you. I have one correction.

Q Would you please share that with the Commission today?

A On page 14, line 4, the figure should be $5,231,155,391. That is $5,231,155,391. This change matches the total listed in the second column of Table 1 on page 15 of my testimony.

Q All right. And as modified and corrected, do you adopt your prefiled testimony as your testimony today?

A Yes, I do.

Q And for this proceeding you are being offered as a fact witness; is that correct?

A Yes, that is correct.

Q And your testimony is based upon the best factual information available at the time you filed your testimony; is that correct?

A Yes, it is.

Q And has new updated factual information become available since the filing of your testimony?

A Yes, it has.

Q All right. And you will address that briefly in your summary; is that correct?

A Yes, it is.

MR. SAYLER: All right. Mr. Chairman, I would ask that the prefiled testimony of Mr. Noriega be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Noriega's prefiled direct testimony with the one correction into the record as though read.

BY MR. SAYLER:

Q Thank you. And did you prepare three exhibits for your direct testimony, TN-1, 2, and 3?

A Yes, I did.

MR. SAYLER: The witness has three exhibits, and for the record those have been assigned hearing Exhibit Nos. 53, 54, and 55 in the Comprehensive Exhibit List.

CHAIRMAN GRAHAM: Duly noted.

DIRECT TESTIMONY

OF

TARIK NORIEGA

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 150001-EI

I. EDUCATIONAL BACKGROUND AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Tarik Noriega. My business address is 111 W. Madison St., Suite 812, Tallahassee, FL 32399-1300.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Office of Public Counsel ("OPC") as a Legislative Analyst.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Central Florida with a Bachelor of Arts ("B.A.") degree in Economics in 1992. I earned a Master of Arts in Applied Economics ("M.A.A.E.") degree from the University of Central Florida in 1994.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A. In 1996, I began employment as a Regulatory Analyst with the Forecasting Section of the Florida Public Service Commission ("PSC" or "Commission"), where I was responsible for evaluating electric utility load forecasts and reporting findings and conclusions during electric utility ten-year site plan reviews and power plant need determination proceedings. I also participated in several audits, designed consumer surveys, developed policy analysis projects, made presentations to the Commissioners, represented the agency in federal proceedings, and served as a bilingual (Spanish language) media liaison.

In 2005, I was hired as an Economist by the Florida House of Representatives, where I prepared bill analyses, tracked revenues and the fiscal impacts of legislation, participated in the Revenue Estimating Conference ("REC") process, analyzed economic trends, reviewed all relevant economic forecasts, and was a lead analyst in addressing emergency management, property tax, and local tax issues. In addition, I worked in the appropriations process and made recommendations regarding the PSC's budget.

In 2011, I began employment as a Research Economist in the Office of Tax Research at the Florida Department of Revenue, where I was the lead analyst in developing state documentary stamp tax and intangibles tax forecasts for the REC. I also prepared fiscal impacts for the REC and assisted in the development of the state's ad valorem tax forecast.

Since 2012, I have been working primarily as an Economist for OPC, where I provide technical support in rate cases and other docketed and undocketed matters before the PSC on behalf of Florida's utility customers.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN PROCEEDINGS BEFORE THE COMMISSION?

A. No, I have not.

II. TESTIMONY OVERVIEW

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of OPC and the customers served by the four largest Florida investor-owned electric utilities ("IOUs" or "Companies").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to provide factual testimony related to the history of the fuel clause, mid-course corrections, and hedging. I also provide the results of the IOU hedging programs since 2002. Another OPC witness, Mr. Daniel J. Lawton, addresses some of the economic and regulatory policy issues surrounding the Companies' proposals to continue their natural gas financial hedging programs, as described in their 2016 Risk Management Plans. In addition, Mr. Lawton's testimony addresses the potential impacts of the Companies' hedging proposals on consumers, if approved by the Commission.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY UPON FOR YOUR TESTIMONY?

A. As part of this year's Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor Docket ("Fuel Adjustment Clause" or "Fuel Docket"), I have reviewed past hedging true-up filings with the PSC in the Fuel Adjustment Clause by Duke Energy Florida ("Duke"), Florida Power & Light Company ("FPL"), Gulf Power Company ("Gulf"), and Tampa Electric Company ("TECO"), as well as these Companies' discovery responses related to hedging. I did not review any discovery responses or past hedging filings by Florida Public Utilities Company ("FPUC") because that utility does not hedge natural gas. I also reviewed prior Commission Fuel Adjustment Clause orders and hedging orders, and other information available in the public domain. When relying on various sources, I have referenced such sources in my testimony and/or attached these sources as Exhibits.

Q. WHAT IS THE PERIOD THAT YOU REVIEWED IN EVALUATING THE COMPANIES' NATURAL GAS HEDGING FILINGS?

A. I reviewed data for calendar years 2002 to 2014 and the 2015 projected data.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring three Exhibits. Exhibit No. ____ (TN-1) includes my résumé. Exhibit No. ____ (TN-2), titled "IOU Natural Gas Hedging True-up Filings with the PSC", provides excerpts of the Companies' 2002-2014 natural gas hedging true-up filings. Exhibit No. ____ (TN-3), titled "IOU Natural Gas Hedging Results as Reported in Discovery", provides the Companies' responses to OPC's discovery regarding natural gas hedging gains/losses for 2002-2014 and the 2015 projected gains/losses.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section III of my testimony, I address the history of the Fuel Adjustment Clause in Florida, including a brief overview of mid-course corrections.

Section IV provides a general overview of fuel price hedging and the PSC's 2002 and 2008 Hedging Orders.

Section V addresses my observations regarding the IOUs' natural gas hedging gains and losses since 2002.

Section VI provides my conclusion.

III. FUEL ADJUSTMENT CLAUSE BACKGROUND

Q. WHAT IS THE FUEL ADJUSTMENT CLAUSE?

A. The Fuel Adjustment Clause is a mechanism used by the Commission that allows the IOUs to recover "[p]rudently incurred fossil fuel-related expenses..."[1]

[1] Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, In re: Cost Recovery Methods for Fuel-Related Expenses, p. 2.

The origin, purpose, and history of the Fuel Adjustment Clause are thoroughly discussed in two Commission orders: Order No. 6357, issued November 26, 1974, in Docket No. 74680-CI, In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, and Order No. PSC-11-0080-PAA-EI, issued January 31, 2011, in Docket No. 100404-EI, In re: Petition by Florida Power & Light Company to Recover Scherer Unit 4 Turbine Upgrade Costs Through Environmental Cost Recovery Clause or Fuel Cost Recovery Clause. Order No. 11-0080 summarized the Fuel Adjustment Clause as follows:

> The fuel [adjustment] clause is a regulatory tool designed to pass through to utility customers the costs associated with fuel purchases. The purpose is to prevent regulatory lag, which occurs when a utility incurs expenses but is not allowed to collect offsetting revenues until the regulatory body approves cost recovery. Regulatory lag has historically been a problem for utilities because of the volatility of fuel costs. ... Different states have addressed volatile fuel costs and the problem of regulatory lag in differing ways. Several jurisdictions, like Florida, have allowed recovery of fuel costs in a fuel adjustment clause, and in Florida the implementation of the fuel clause has changed and developed over the years.[2]

Q. ARE UTILITIES ALLOWED TO PROFIT ON THE FUEL COSTS RECOVERED THROUGH THE FUEL ADJUSTMENT CLAUSE?

A. No. As recognized in Order No. 6357, issued in 1974,"[i]t should be emphasized that a utility does not make a profit on its fuel costs."[3]

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[2] Order No. PSC-11-0080-PAA-EI, issued January 31, 2011, in Docket No. 100404-EI, In re: Petition by Florida Power & Light Company to Recover Scherer Unit 4 Turbine Upgrade Costs Through Environmental Cost Recovery Clause or Fuel Cost Recovery Clause, p. 6. *See also* footnote No. 15 of this Order for an additional description of the purpose of the Fuel Adjustment Clause, p. 8.

[3] Order No. 6357, issued November 26, 1974, in Docket No. 74680-CI, In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, p. 2.

Q. WHEN DID THE COMMISSION BEGIN AUTHORIZING FUEL COST RECOVERY?

A. The practice of allowing cost recovery through a fuel adjustment mechanism began in the mid-1920s, predating the Commission's jurisdiction over regulated electric utilities, and has evolved over the past 90 years.[4]

Q. PLEASE DESCRIBE THE EVOLUTION OF THE FUEL COST RECOVERY PROCESS OVER TIME.

A. Utilities benefited from a monthly fuel adjustment mechanism from 1925 to 1951, prior to the PSC's oversight of regulated electric utilities. After the Legislature granted the Commission jurisdiction over regulated electric utilities in 1951, the utilities applied a Commission-approved formula and placed the resulting fuel charge on customers' bills. The Commission staff performed some auditing functions; however, no formal public hearing was held.[5]

That fuel adjustment mechanism changed in 1974 when customers became increasingly concerned over increased fuel charges as a result of the Organization of Petroleum Exporting Countries' ("OPEC's") oil embargo, which substantially increased the cost of oil.[6] Following an Attorney General Opinion which stated "that the practice of allowing changes in the fuel adjustment charges without a public hearing was illegal

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[4] *See* Order No. 6357 at 2; *see also* Order No. PSC-11-0080-PAA-EI at 6.

[5] Order No. PSC-11-0080-PAA-EI at 6.

[6] Id.; *see also* Order No. 6357 at 1.

under Florida law…" (*See* 74 Op. Att'y. Gen. Fla. 309 (1974)), the Commission held its first fuel adjustment clause hearing.[7] At this hearing, a stipulation was approved that provided for a monthly hearing for all fuel adjustment clauses.[8] During the same 1974 proceeding, the Commission considered a recommendation on how to modify the clause and, as an incentive for utilities to optimize fuel costs, implemented a two-month lag between the filing for fuel clause recovery and the Commission's decision on cost recovery.[9]

However, because the amount of work involved in reviewing the information and the resulting lag time presented difficulties for the Commission, the utilities, customers, and intervenor parties alike, the Commission modified the clause once again in 1980.[10] By Order No. 9273, the Commission modified the recovery clauses to allow recovery on the projections of future fuel and fuel-related expenditures subject to a true-up hearing, during which the utilities' projected fuel expenditures were adjusted to recover only actual expenditures.[11]

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[7] Order No. PSC-11-0080-PAA-EI at 6.

[8] Id.

[9] Id.

[10] Order No. 9273, issued March 7, 1980, in Docket No. 74680-CI, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of Staff's Proposed Projected Fuel and Purchased Power Cost Recovery Clause with an Incentive Factor.

[11] Id.; *see also* Order No. 9451, issued July 15, 1980, in Docket No. 800119-EU, In re: Petition of Florida Power Corporation for Authority to Increase Its Retail Rates and Charges, p. 2.

By this Order, the PSC also modified its fuel adjustment hearings by changing the hearing schedule from once a month to every six months. In justifying its rationale, the Commission stated "there are certain advantages to adoption of the six month perojection (sic) period, such as overcoming the seasonal peaks and valleys which would otherwise offest (sic) the attempt to arrive at a levelized charge. We therefore find that a six month projection period should be used."[12] Once adopted, these semi-annual fuel adjustment hearings were held until 1998 when the PSC changed the frequency and timing of cost recovery hearings from semi-annual to annual.[13]

Q. WHY DID THE COMMISSION CHANGE THE FREQUENCY OF COST RECOVERY HEARINGS FROM SEMI-ANNUAL TO ANNUAL?

A. On March 17, 1998, the PSC held a workshop to receive comments from the IOUs and other interested parties regarding proposed changes to the frequency and timing of the four cost recovery clauses.[14] On May 19, 1998, the Commission issued Order No. PSC-98-0691-FOF-PU, which changed the frequency of fuel adjustment hearings from semi-annual to its current annual schedule. In this Order, the PSC found "that all components of the fuel clause for all investor-owned electric utilities should be prospectively calculated and set on a twelve-month projected basis at annual

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[12] *See* Order No. 9273 at 6.

[13] Order No. PSC-98-0691-FOF-PU, issued May 19, 1998, in Docket No. 980269-PU, In re: Consideration of Change in Frequency and Timing of Hearings for Fuel and Purchased Power Cost Recovery Clause, Capacity Cost Recovery Clause, Generating Performance Incentive Factor, Energy Conservation Cost Recovery Clause, Purchased Gas Adjustment (PGA) True-up, and Environmental Cost Recovery Clause, p. 13.

[14] Id., p. 2.

hearings."[15] Also, the Commission stated that this change was "in the public interest" for the following reasons: (1) an annual fuel hearing will reduce the number of hearings days per year reserved for the fuel clause; (2) mid-course corrections may occur less frequently; and (3) an annual factor will provide customers with more certain and stable prices. When discussing that mid-course corrections may occur less frequently as a result of annual Fuel Adjustment Clause proceedings, the Commission stated that "fuel prices are currently less volatile and a higher probability exists that monthly over-recoveries and under-recoveries will be offset between annual fuel clause hearings. Hence, midcourse (sic) corrections may occur less frequently than previously surmised."[16]

Q. WHAT IS A MID-COURSE CORRECTION?

A. A mid-course correction is a mechanism set forth by a Commission rule adopted in 2010.[17] This rule requires utilities to seek a mid-course correction if there is a 10% or greater over/under-recovery in fuel cost recovery or capacity cost recovery factors, or to explain why a mid-course correction is not practical. However, the utilities can also request a mid-course correction without reaching the 10% threshold requiring Commission notification.[18]

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[15] Id., p. 4.

[16] Id.

[17] Rule 25-6.0424, Florida Administrative Code.

[18] Id.

Q. HOW MANY MID-COURSE CORRECTIONS DID THE COMPANIES REQUEST DURING YOUR REVIEW PERIOD (2002 TO 2014)?

A. The IOUs requested 15 mid-course corrections from 2002 to 2014. According to their responses to OPC's discovery, FPL filed 6 mid-course corrections (3 for over-recoveries and 3 for under-recoveries), Gulf filed 3 (2 for over-recoveries and 1 for an under-recovery), and TECO filed 2 (1 for an over-recovery and 1 for an under-recovery).[19] According to its Commission Fuel Docket filings, Duke requested 4 mid-course corrections (2 for over-recoveries and 2 for under-recoveries).[20]

IV. FUEL PRICE HEDGING

Q. HAS THE COMMISSION INDICATED ITS INTENT FOR DEVELOPING A HEDGING PROGRAM IN FLORIDA?

A. Yes. In Order No. PSC-02-1484-FOF-EI (the "2002 Hedging Order"), issued October 30, 2002, the Commission stated that:

> The Proposed Resolution of Issues establishes a framework and direction for the Commission and the parties to follow with respect to risk management for fuel procurement. It provides for the filing of information in the form of risk management plans and as part of each IOU's final true-up filing in the fuel and purchased power cost recovery docket, which will allow the Commission and the parties to monitor each IOU's practices and transactions in this area. In addition, it

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[19] *See* FPL's response to OPC Interrogatory No. 30; Gulf's response to OPC Interrogatory No. 6; and TECO's response to OPC Interrogatory No. 6.

[20] *See* Order No. PSC-02-0655-AS-EI, issued May 14, 2002, in Docket Nos. 000824-EI and 020001-EI, In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light; Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. *See* Order No. PSC-03-0382-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. *See* Order No. PSC-08-0495-PCO-EI, issued August 5, 2008, in Docket No. 080001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. *See* Order No. PSC-10-0738-FOF-EI, issued December 20, 2010, in Docket No. 100001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.

> maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Further, the Proposed Resolution of Issues appears to remove disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.[21]

Q. HAS THE COMMISSION MODIFIED ITS INTENT FOR FUEL HEDGING IN FLORIDA OR PROVIDED HEDGING GUIDELINES?

A. Yes. In Order No. PSC-08-0667-PAA-EI (the "2008 Hedging Order"), issued October 8, 2008, the Commission established guiding principles that it recognized as appropriate to follow in reviewing plans and an IOU's hedging activities.[22] The first two guiding principles are:

> a. The Commission finds that the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers, in the face of price volatility for the fuels (and fuel price-indexed purchased power energy costs) that the IOU must pay in order to provide electric service.
>
> b. The Commission finds that a well-managed hedging program does not involve speculation or attempting to anticipate the most favorable point in time to place hedges. Its primary purpose is not to reduce an IOU's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs paid by customers over time.[23]

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[21] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of Investor-owned Electric Utilities' Risk Management Policies and Procedures, p. 2.

[22] Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor. Note: the Commission clarified the 2002 Hedging Order in May 2008. *See* Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI. In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.

[23] Order No. PSC-08-0667-PAA-EI, p. 16.

Q. ARE YOU AWARE OF ANY ORDERS THAT HAVE MODIFIED THE UNDERLYING BASIS FOR THE COMMISSION'S APPROVAL OF THE UTILITY HEDGING PROGRAMS?

A. No. I have been advised by counsel that neither the Woodford Project Order[24] nor the Natural Gas Reserves Investment Guidelines Order[25] modified the Commission's basic intent that utility hedging programs are designed to reduce fuel price volatility.

Q. DO ANY OF THE HEDGING ORDERS PRECLUDE ANY PARTY FROM PETITIONING FOR THE SUSPENSION OR TERMINATION OF THE FUEL HEDGING PROGRAM IN FLORIDA?

A. No, I have been advised by counsel that they do not.

V. OBSERVATIONS

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS REGARDING THE COMPANIES' NATURAL GAS HEDGING GAINS AND LOSSES FOR THE PERIOD FROM 2002 TO 2014.

A. In order to ascertain the magnitude of the Companies' hedging gains or losses, I reviewed the Companies' hedging true-up filings with the Commission for every year from 2002 through 2014. These filings consisted of testimonies and exhibits, which included a summary of the Companies' hedging activities and indicated whether or not

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[24] Order No. PSC-15-0038-FOF-EI, issued January 12, 2015, in Docket No. 150001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.

[25] Order No. PSC-15-0284-FOF-EI, issued July 14, 2015, in Docket No. 150001-EI, In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.

the Companies achieved any gains or losses related to those hedging activities. My review of the Companies' hedging true-up filings shows that each of the IOUs experienced cumulative natural gas hedging losses from 2002 to 2014, which totaled $5,231,155,391 JB ~~$5,233,201,193~~ for all four Companies. In addition, my review of the Companies' responses to OPC's discovery for the same period shows cumulative natural gas hedging losses of $5,552,505,043.

Q. DID YOU COMPARE THE COMPANIES' NATURAL GAS HEDGING GAINS OR LOSSES FILED WITH THE COMMISSION IN THIS DOCKET WITH THE COMPANIES' RESPONSES TO OPC'S DISCOVERY?

A. Yes, I did. The Companies' natural gas hedging true-up filings with the PSC are attached as Exhibit TN-2, and the Companies' natural gas hedging discovery responses are attached as Exhibit TN-3. The natural gas hedging losses from 2002 to 2014 for the IOUs are summarized on Table 1 below:

Table 1 – Comparison of Natural Gas Hedging Commission Filings and Discovery Responses (2002-2014)[26]

IOU	Commission Filings (2002-2014)	Discovery Responses (2002-2014)	Difference Between Commission Filings and Discovery Responses	End Result
Duke	$ (1,233,387,898)	$ (1,267,848,634)	$ 34,460,736	Under-reported loss
FPL	$ (3,500,752,265)	$ (3,775,960,449)	$ 275,208,184	Under-reported loss
Gulf	$ (127,463,543)	$ (127,278,227)	$ (185,316)	Over-reported loss
TECO	$ (369,551,685)	$ (381,417,733)	$ 11,866,048	Under-reported loss
TOTALS	$ (5,231,155,391)	$ (5,552,505,043)	$ 321,349,652	N/A

Q. WHAT DID YOU OBSERVE?

A. For the most part, there were some minor discrepancies between the Companies' fuel clause hedging filings and the Companies' responses to OPC's hedging discovery. However, in at least once instance, the annual discrepancy for one of the IOUs exceeded $100 million dollars.

[26] *See* Exh. TN-2 and TN-3.

Q. PLEASE DESCRIBE THOSE DISCREPANCIES.

A. In general terms, the amount of the loss or gain reported to the Commission was sometimes different than what was reported in discovery. For example, in its Commission hedging true-up testimony from 2004-2010, TECO used approximate numbers, rounded to the nearest hundred thousand dollars; however, TECO used exact numbers in its response to OPC discovery. Also, in three instances the Companies' hedging losses were considered confidential, so I was unable to include those losses in Table 1 showing cumulative hedging losses. Additionally, there were some smaller differences between what was reported by Duke and Gulf, but those differences were rather minor in comparison to some of the larger discrepancies I found. Some of the specific discrepancies are discussed further below.

Q. DO YOU HAVE AN OPINION ON WHY THE COMPANIES HAD DISCREPANCIES BETWEEN THEIR COMMISSION HEDGING TRUE-UP FILINGS AND THEIR DISCOVERY RESPONSES?

A. No, I do not. My testimony is limited to reporting and summarizing the information submitted by the IOUs to the PSC and the discovery responses provided to OPC.

Q. YOU INDICATED THAT THERE WERE SOME LARGER DISCREPANCIES. WOULD YOU PLEASE DESCRIBE WHAT YOU OBSERVED?

A. For the years 2004 and 2005, it appears that FPL over-reported hedging gains. And, for the years 2006 and 2007, it appears that FPL under-reported hedging losses. There was also a smaller discrepancy for 2002 that was less than $1 million. Table 2 below shows the larger discrepancies for FPL:

Table 2 – Comparison of FPL's Natural Gas Hedging Commission Filings and Discovery Responses (2004-2007)[27]

FPL	Commission Filings	Discovery Responses	Difference from PSC Filing	End Result
2004	$ 191,564,536[28]	$ 156,275,728	$ 35,288,808	Over-reported gain
2005	$ 519,388,788	$ 488,815,538	$ 30,573,250	Over-reported gain
2006	$ (416,637,197)	$ (487,636,397)	$ 70,999,200	Under-reported loss
2007	$ (799,268,428)	$ (918,863,078)	$ 119,594,650	Under-reported loss

Q. DO YOU HAVE AN OPINION ON WHY SOME GAINS WERE OVER-REPORTED AND SOME LOSSES WERE UNDER-REPORTED FOR THE YEARS 2004 THROUGH 2007, OR WHAT MIGHT HAVE CAUSED THOSE DISCREPANCIES?

A. No, I do not. Table 2 is based solely on a review of FPL's true-up hedging activities

[27] The Commission Filings column showing FPL's hedging gains (losses) was derived from the non-confidential testimony and exhibits of FPL witness Gerard J. Yupp filed in the Fuel Docket (*see* Exh. TN-2, pp. 44-55). The Discovery Responses column showing gains (losses) was obtained from FPL's response to OPC's Interrogatory No. 26 (*see* Exh. TN-3, pp. 11-12).

[28] This figure was provided on April 3, 2006, presumably to revise the original figure of $189,877,494 filed on April 1, 2005. However, the revised figure listed on Table 2 is still different from what FPL reported in its May 2015 discovery response.

filings for every year from 2002 through 2014, which are filed with the Commission on or around April 1 of each year. While it is possible that FPL corrected those larger discrepancies for the years 2004 through 2007, the Fuel Dockets contain hundreds of filings from the four IOUs, and I did not examine every Fuel Adjustment Clause filing to see if FPL had made corrections to its hedging true-up filings with the PSC for the years in question.

Q. WHAT ARE THE COMPANIES' PROJECTED NATURAL GAS HEDGING GAINS OR LOSSES FOR 2015?

A. In their discovery responses submitted in May 2015, each of the Companies projected a natural gas hedging loss for 2015. These projected losses are summarized in Table 3 below:

Table 3 – Projected 2015 Natural Gas Hedging Gains (Losses) For IOUs[29]

IOU	Projected Natural Gas Hedging Gains (Losses) (2015)
Duke	$ (196,900,000)
FPL	$ (382,000,000)
Gulf	$ (43,981,755)
TECO	$ (23,168,465)
TOTAL	$ (646,050,220)

[29] *See* Duke's Supplemental Response to OPC Interrogatory No. 5; FPL's Response to OPC Interrogatory No. 29; Gulf's Response to OPC Interrogatory No. 5; and TECO's Response to OPC Interrogatory No. 5 (*see* Exh. TN-3, pp. 5-6, 13, 18, and 24).

VI: CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSION.

A. As a fact witness in this proceeding, my conclusion is that the facts confirm that the Companies' natural gas hedging programs have resulted in losses exceeding $5 billion for Florida customers from 2002 to 2014. In addition, losses are currently projected to exceed $600 million for 2015 alone.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BY MR. SAYLER:

Q Have you prepared a summary of your testimony today?

A Yes, I have.

Q All right. Would you please summarize your testimony?

A Yes. Thank you.

Good afternoon, Commissioners, Chairman and Commissioners. The purpose of my testimony is to provide facts about the history of the fuel clause, midcourse corrections, and hedging. I also provide the results of the investor-owned utility hedging programs since 2002.

I reviewed the hedging true-up Commission filings from 2002 to 2014 for the four investor-owned utilities that hedge natural gas. These filings consisted of testimonies and exhibits which included a summary of hedging activities and indicated whether or not the company has achieved any gains or losses related to those hedging activities.

My review of the hedging true-up filings shows that each of the investor-owned utilities experienced natural gas hedging results from 2002 to 2014 which totaled approximately $5.2 billion in cumulative net losses for the four companies. Also, my review of the companies' responses to OPC's discovery in this docket for the same period shows even higher cumulative net natural gas hedging losses in excess of $5.5 billion for the four investor-owned utilities.

During my review, I also observed discrepancies between the companies' fuel clause hedging filings and the companies' responses to OPC's hedging discovery. In some cases, these discrepancies were the result of rounding, while in others it was either due to the confidentiality of the information or to subsequent revisions by the utilities.

As a matter of accuracy, my testimony was based on the best information available to OPC at the time of filing on September 23rd. In early October Tampa Electric conferred with OPC to discuss their discrepancies, and all of these have been successfully reconciled.

Also, Florida Power & Light provided a revised interrogatory response on October 9th to correct the inadvertent double counting of the cost of option premiums in the total gains and losses from 2002 to 2007, which I relied upon for my testimony. I concur with Florida Power & Light's revised interrogatory response. Therefore, based on the latest information available, the data shows that the cumulative net hedging losses from 2002 to 2014 for Florida's investor-owned utility customers totaled approximately $5.3 billion.

In addition, my review of the 2015 projected data indicates that each of the companies' projected a 2015 natural gas hedging loss as shown in their discovery responses to OPC. The 2015 projected losses for the four companies alone will cost Florida's investor-owned utility customers approximately $646 million.

In conclusion, if you add the 2015 projected losses to the actual cumulative net hedging losses from 2002 to 2014, these natural gas hedging programs will have cost Florida's investor-owned utility customers approximately $6 billion by the end of this year. That concludes my summary. Thank you.

MR. SAYLER: Mr. Chairman, we tender the witness for cross.

(Volume concluded at 12:10 p.m.)

(Transcript continues in sequence with Volume 5.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 4th day of November, 2015.

Linda Boles

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