FILED NOV 03, 2015
DOCUMENT NO. 07006-15
FPSC - COMMISSION CLERK

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 2

(Pages 221 through 433)

PROCEEDINGS: HEARING

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

DATE: Monday, November 2, 2015

TIME: Commenced at 1:38 p.m.
Concluded at 3:32 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.
1 through 114 - (As identified on the Comprehensive Exhibit List)		304	
1, 7 through 24, 28 through 31, 40 through 49, 68, 70, 71, 73, 75 through 104			305
115	- FPL Response to OPC Rogs	413	
116	- DEF Response to OPC Rogs	413	
117	- Gulf Response to OPC Rogs	414	
118	- TECO Response to OPC Rogs	414	
119	- E&Y "The Pros and Cons of Hedging"	420	

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 3/3/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs Department.

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 18 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2014 through December 2014 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"), the Capacity Cost Recovery Clause ("Capacity Clause") as well as the wholesale incentive benchmark for January 2015 through December 2015.

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

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (PAR-1), consisting of five documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2014 through December 2014?

A. The final true-up amount for the Capacity Clause for the period January 2014 through December 2014 is an over-recovery of $140,386.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2014

Through December 2014", provides the calculation for the final over-recovery of $140,386. The actual capacity cost over-recovery, including interest, was $106,860 for the period January 2014 through December 2014 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $33,526 actual/estimated under-recovery approved in Order No. PSC-14-0701-FOF-EI issued December 19, 2014 in Docket No. 140001-EI, results in a final over-recovery of $140,386 for the period, as identified in Document No. 1, page 4 of 4. This over-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2016 through December 2016.

Q. What is the estimated effect of this $140,836 over-recovery for the January 2014 through December 2014 period on residential bills during January 2016 through December 2016?

A. The $140,386 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.01.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2014 through December 2014?

A. The final Fuel Clause true-up for the period January 2014 through December 2014 is an under-recovery of $2,919,025. The actual fuel cost over-recovery, including interest, was $10,467,182 for the period January 2014 through December 2014. This $10,467,182 amount, less the $13,386,207 actual/estimated over-recovery amount approved in Order No. PSC-14-0701-FOF-EI, issued December 19, 2014 in Docket No. 140001-EI, results in a net under-recovery amount for the period of $2,919,025.

Q. What is the estimated effect of the $2,919,025 under-recovery for the January 2014 through December 2014 period on residential bills during January 2016 through December 2016?

A. The $2,919,025 under-recovery will increase a 1,000 kWh residential bill by approximately $0.16.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2014 Through December 2014". It shows the calculation of the final fuel under-recovery of

$2,919,025.

Line 1 shows the total company fuel costs of $752,417,226 for the period January 2014 through December 2014. The jurisdictional amount of total fuel costs is $752,417,226, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual under-recovered fuel costs for the period, shown on line 4. The resulting $13,100,095 under-recovered fuel costs for the period, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery of $10,467,182 shown on line 9. The $10,467,182 actual over-recovery amount less the $13,386,207 actual/ estimated over-recovery amount shown on line 10, results in a final $2,919,025 under-recovery amount for the period January 2014 through December 2014 as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2014 Through December

2014." It shows the calculation of the actual over-recovery compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2014 through December 2014?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $19,629,289 more than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2014 through December 2014?

A. As shown on line C3 of Document No. 3, the company collected $7,040,709, or 1.0 percent greater jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of transactions for each of Commission Schedules A6, A7, A8, A9, as well as capacity information on Schedule A12.

Q. Please describe Document No. 5 of your exhibit.

A. Document No. 5 provides the Polk Unit 1 ignition oil conversion project capital costs and fuel savings for the period January 2014 through December 2014. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period are $4,429,920. The project fuel savings are $38,000,021, which exceeds the capital costs by $33,570,101, as shown on Document No. 5, page 1, line 33. Therefore, the Polk Unit 1 ignition oil conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Wholesale Incentive Benchmark

Q. What is Tampa Electric’s wholesale incentive benchmark for 2015, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2015 benchmark is $1,479,981, which is the three-year average of $246,931, $894,045 and $3,298,966 actual gains on non-separated wholesale sales, excluding emergency sales, for 2012, 2013 and 2014, respectively.

Q. Does this conclude your testimony?

A. Yes.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs Department.

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility. I have accumulated 18 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2015 through December 2015 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2016 through December 2016 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2015, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2016 fuel and purchased power costs and capacity cost recovery factors.

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

A. Yes. I have prepared Exhibit No. ____ (PAR-2), which consists of three documents. Document No. 1 includes

Schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2015 through December 2015. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2015 through December 2015. Document No. 3 provides the actual/ estimated capital costs and fuel savings during the period of January 2015 through December 2015 for capital projects authorized for cost recovery through the fuel clause. Document No. 3 also provides the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the project. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2016 through December 2016 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2016 through December 2016 is an over-recovery of $27,590,550.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2016 through December 2016 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2016 is the sum of the final true-up amount for the period January 2014 through December 2014 and the actual/estimated true-up amount for the period January 2015 through December 2015.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2014?

A. The final true-up was an under-recovery of $2,919,025. The actual fuel cost over-recovery, including interest was $10,467,182 for the period January 2014 through December 2014. The $10,467,182 amount, less the actual/estimated over-recovery amount of $13,386,207 approved in Order No. PSC-14-0701-FOF-EI, issued December 19, 2014 in Docket No. 140001-EI resulted in a net under-recovery amount for the period of $2,919,025.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2015 through December 2015?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $30,509,575 for the January 2015 through December 2015 period. The detailed calculation supporting the actual/ estimated current period true-up is shown in Exhibit No. ____ (PAR-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2016 through December 2016 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2016 through December 2016 is an over-recovery of $2,203,769 as shown in Exhibit No. ____ (PAR-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2016 through December 2016 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2016 capacity cost recovery factors is the sum of the final true-up amount for 2014 and the actual/estimated true-up amount for January 2015 through December 2015.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2014?

A. The final 2014 true-up is an over-recovery of $140,386. The actual capacity cost over-recovery including interest was $106,860 for the period January 2014 through December 2014. This amount, less the $33,526 actual/estimated under-recovery amount approved in Docket No. 140001-EI, Order No. PSC-14-0701-FOF-EI, issued December 19, 2014 results in a net over-recovery amount for the period of $140,386 as identified in Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2015 through December 2015?

A. The actual/estimated true-up amount is an over-recovery of $2,063,383 as shown on Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the actual/estimated Polk Unit 1 ignition oil conversion project costs for the period January 2015 through December 2015?

A. The actual/estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $4,109,281. This is shown in Exhibit No. ____ (PAR-2), Document No. 3.

Q. Did Tampa Electric's actual/estimated Polk Unit 1 ignition oil conversion project fuel savings exceed actual/estimated costs for the period January 2015 through December 2015?

A. Yes, as reflected in Exhibit No. ___ (PAR-2), Document No. 3, fuel savings exceeded costs for the period January 2015 through December 2015.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2015 through December 2015 actual/ estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on

September 27, 2012.

Q. What did Tampa Electric calculate as the actual/estimated Big Bend ignition oil conversion project costs for the period January 2015 through December 2015?

A. The actual/estimated Big Bend ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $3,744,426. This is shown in Exhibit No. ____ (PAR-2), Document No. 3.

Q. Did Tampa Electric's actual/estimated Big Bend ignition oil conversion project fuel savings exceed actual/ estimated cost for the period of January 2015 through December 2015.

A. Yes, as reflected in Exhibit No. ___ (PAR-2), Document No. 3, fuel savings exceeded costs for the period January 2015 through December 2015.

Q. Should Tampa Electric's Big Bend ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2015 through December 2015 actual/ estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates used to calculate the revenue requirement rate of return for these two projects.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company’s projects that are approved for recovery through the fuel clause are shown in Document No. 3.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 09/01/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs Department.

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 18 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2016 through December 2016. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2016.

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

A. Yes. Exhibit No. ____ (PAR-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2016 through December 2016 as well as Schedule H1 for January through December, 2013 through 2016. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company’s projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

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

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (PAR-3), Document No. 1, Tampa Electric requests recovery of $28,290,255 after jurisdictional separation and prior year true-up, for estimated expenses in 2016.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2016 through December 2016.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.178	
GS and TS Secondary	0.166	
GSD, SBF Standard		
Secondary		0.53

Primary		0.52
Transmission		0.52
IS, IST, SBI		
Primary		0.43
Transmission		0.42
GSD Optional		
Secondary	0.123	
Primary	0.122	
LS1 Secondary	0.021	

These factors are shown in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.151 cents per kWh compare to the factor for January 2015 through December 2015?

A. The proposed capacity cost recovery factor is 0.021 cents per kWh (or $0.21 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.172 cents per kWh for the January 2015 through December 2015 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2016?

A. The appropriate amount for the 2016 period is 3.676 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (PAR-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2016 through December 2016.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,258,600, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2015 through December 2015 period. The net true-up amount for this period is an over-recovery of $27,590,550.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2016 through

December 2016. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ____ (PAR-3), Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2016 through December 2016.

A.

Metering Voltage Level	Fuel Charge Factor (cents per kWh)
Secondary	3.676
Tier I (Up to 1,000 kWh)	3.361
Tier II (Over 1,000 kWh)	4.361
Distribution Primary	3.639
Transmission	3.602
Lighting Service	3.627
Distribution Secondary	3.937 (on-peak)
	3.564 (off-peak)
Distribution Primary	3.898 (on-peak)
	3.528 (off-peak)
Transmission	3.858 (on-peak)
	3.493 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.676 cents per kWh compare to the levelized fuel adjustment factor for the January 2015 through December 2015 period?

A. The proposed fuel charge factor is 0.198 cents per kWh (or $1.98 per 1,000 kWh) lower than the average fuel charge factor of 3.874 cents per kWh for the January 2015 through December 2015 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2016 fuel and purchased power and capacity cost recovery projections?

A. Yes. There is one significant event reflected in the 2016 projections: the purchase of additional natural gas for use at Big Bend Station. This is described in the testimony of witness J. Brent Caldwell.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project costs for the period January 2016 through December 2016?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2016 through December 2016 are $3,812,311. This is shown in Exhibit No. _____ (PAR-3), Document No. 4.

Q. Does Tampa Electric's estimated Polk Unit 1 ignition oil conversion project fuel savings exceed estimated costs for the period January 2016 through December 2016?

A. Yes, as reflected in Exhibit No. _____ (PAR-3), Document No. 4, fuel savings exceed costs for the period January 2016 through December 2016.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2016 through December 2016 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2016 through December 2016?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2016 through December 2016 are $4,894,041. This is shown in Document No. 4 of my exhibit.

Q. Does Tampa Electric's estimated Big Bend ignition oil conversion project fuel savings exceed estimated costs for the period of January 2016 through December 2016?

A. Yes, fuel savings exceed costs for the period January 2016 through December 2016. This information is also presented in Document No. 4 of my exhibit.

Q. Should Tampa Electric's Big Bend Units 1-4 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2016 through December 2016 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates used to calculate the revenue requirement rate of return for these two projects.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company’s projects that are approved for recovery through the fuel clause are shown in Document No. 4.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric’s projected wholesale incentive benchmark for 2016?

A. The company’s projected 2016 benchmark is $1,532,270, which is the three-year average of $894,045, $3,298,966 and $403,800 in gains on the company’s non-separated wholesale sales, excluding emergency sales, for 2013, 2014 and 2015 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2016 from non-separated wholesale sales to exceed its 2016 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2016. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $2.25 beginning January 2016, when compared to the January 2015 through October 2015 charges. These charges are shown in Exhibit No. ____ (PAR-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2016.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 03/17/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2014 through December 2014. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2014 - December 2014 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2014 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2014 through December 2014 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 1.682 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $1,258,600 for the period.

Q. Please proceed with your review of the actual results for the January 2014 through December 2014 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $2,044,549,944. This produces the maximum penalty or reward amount of $7,480,950 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission’s Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 2,017.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 493.9 planned outage hours. Consequently, the actual equivalent availability of 83.5 percent is adjusted to 68.2 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 577.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 735.9 planned outage hours. Consequently, the actual equivalent availability of 81.0 percent is adjusted to 82.6 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 575.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 449.0 planned outage hours. Consequently, the actual equivalent availability of 79.0 percent is adjusted to 77.8 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 1,584.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 1,813.2 planned outage hours. Consequently, the actual equivalent availability of 68.1 percent is adjusted to 70.3 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 455.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 437.7 planned outage hours. Consequently, the actual equivalent availability of 91.7 percent is adjusted to 91.5 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 432.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 539.7 planned outage hours. Consequently, the actual equivalent availability of 82.3 percent is adjusted to 83.5 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 432.0 planned outage hours were originally scheduled for 2014. Actual outage activities required 436.3 planned outage hours. Consequently, the actual equivalent availability of 89.6 percent is adjusted to 89.7 percent, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective GPIP table for each particular unit, shown on pages 7 of 32 through 13 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric’s seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2014 through December 2014 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, 1.682, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $1,258,600.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
FILED: 09/01/2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Compliance and Performance.

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

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

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

A. Yes, Exhibit No. ____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2016 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. Big Bend Unit 2, Big Bend Unit 3, and Polk Unit 1 outages were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes. Big Bend Units 1-4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2016 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent

Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2016 period, the projected EUOF for Bayside Unit 1 is 6.2 percent, and the POF is 17.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 76.1 percent or:

$$100\% - (6.2\% + 17.8\%) = 76.1\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.80 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (6.2\%) + 0.95\ (17.8\%)] = 78.2\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40\ (EUOF_T) + 1.10\ (POF_T)]$$

Again, continuing with the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (6.2\%) + 1.10\ (17.8\%)] = 71.8\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2016 are shown on page 21 of Document No. 1. Five GPIF units have a major outage of 28 days or greater in 2016; therefore, five Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from January 30, 2016 to February 7, 2016 and September 24, 2016 to November 18, 2016. There are 1,561 planned outage hours scheduled for the 2016 period, and a total of 8,784 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 17.8 percent or:

$$\frac{1{,}561}{8{,}784} \times 100\% = 17.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 6.6 percent. Big Bend Unit 2 has a POF of 18.0 percent. Big Bend Unit 3 has a POF of 12.3 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 10.4 percent. Bayside Unit 1 has a POF of 17.8 percent, and Bayside Unit 2 has a POF of 10.6 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. Projected factors are based upon historical unit performance. For each unit the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 6.2 percent for Bayside Unit 1. The EUOF for Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

or

$$EUOF = \frac{(219 + 322)}{8,784} \times 100\% = 6.2\%$$

Relative to Bayside Unit 1, the EUOF of 6.2 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 14.7 percent. The unit will have two planned outages in 2016, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 78.7 percent.

Big Bend Unit 2

The projected EUOF for this unit is 13.2 percent. The unit will have two planned outages in 2016, and the POF is 18.0 percent. Therefore, the target equivalent availability for this unit is 68.7 percent.

Big Bend Unit 3

The projected EUOF for this unit is 11.1 percent. The unit will have two planned outages in 2016, and the POF is 12.3 percent. Therefore, the target equivalent availability for this unit is 76.6 percent.

Big Bend Unit 4

The projected EUOF for this unit is 16.5 percent. The unit will have two planned outages in 2016, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 76.9 percent.

Polk Unit 1

The projected EUOF for this unit is 8.1 percent. The unit will have two planned outages in 2016, and the POF is 10.4 percent. Therefore, the target equivalent availability for this unit is 81.5 percent.

Bayside Unit 1

The projected EUOF for this unit is 6.2 percent. The unit will have two planned outages in 2016, and the POF is 17.8 percent. Therefore, the target equivalent availability for this unit is 76.1 percent.

Bayside Unit 2

The projected EUOF for this unit is 6.3 percent. The unit will have two planned outages in 2016, and the POF is 10.6 percent. Therefore, the target equivalent availability for this unit is 83.1 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 77.6 percent is shown on Page 5 of Document No. 1. This target is similar to the last three years' January through December actual performance.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Bayside Unit 1 on page 19 of Document No. 1. Except for the months of January, February, September, and November, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of January, February, September, and November, the Equivalent Unplanned Outage Rate exceeds the

Equivalent Unplanned Outage Factor due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch and fuel.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2016 period.

A. The heat rate target for Big Bend Unit 1 is 10,683 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 210 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,460 Btu/Net kWh with a range of ± 435 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,654 Btu/Net kWh, with a range of ± 213 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,458 Btu/Net kWh with a range of ± 383 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,191 Btu/Net kWh with a range of ± 354 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,232

Btu/Net kWh with a range of ± 265 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,484 Btu/Net kWh with a range of ± 217 Btu/Net kWh. A zone of tolerance of ± 75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $679,116,440 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $20,269,972 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 14.36 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 1, page 12, if the unit operates at 6,967 average net operating heat rate, fuel savings would equal $2,911,564 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $20,269,972. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2016 is $2,300,227,560. This produces the maximum allowed jurisdictional incentive of $9,386,068 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. As Order No. PSC-13-0665-FOF-EI issued in Docket No. 130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $9,386,068.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$\begin{aligned} GPIP: = (&0.0189\ EAP_{BB1} + 0.0441\ EAP_{BB2} \\ &+ 0.0320\ EAP_{BB3} + 0.0332\ EAP_{BB4} \\ &+ 0.0076\ EAP_{PK1} + 0.0412\ EAP_{BAY1} \\ &+ 0.0844\ EAP_{BAY2} + 0.0690\ HRP_{BB1} \\ &+ 0.1247\ HRP_{BB2} + 0.0659\ HRP_{BB3} \\ &+ 0.1312\ HRP_{BB4} + 0.0651\ HRP_{PK1} \\ &+ 0.1436\ HRP_{BAY1} + 0.1389\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/ deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2016 period?

A. Yes. Document No. 2 entitled “Summary of GPIF Targets” provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of Wholesale Business Development in Tampa Electric's Fuels Management department. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structure, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

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

A. Tampa Electric evaluates potential purchase and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When Tampa Electric considers making a power purchase, the company aggressively searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the

Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs. The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company’s contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric’s system and market conditions allow.

Q. Please describe Tampa Electric’s 2015 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately five percent of the expected energy needs for 2015 will be met using purchased power. This purchased power energy includes economy purchases, qualifying facilities, and existing firm purchased power agreements with Pasco Cogen, Calpine, and Southern Power Company. The testimony in previous years describes each existing firm purchased power agreement. However, in summary, all three purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is 121 MW of intermediate capacity and continues through 2018. Both Calpine and Southern Power Company are peaking purchases with capacities of 117 MW and 160 MW, respectively. The Southern Power Company purchase continues through this year, while the Calpine purchase continues through 2016. All of the aforementioned purchases provide supply reliability, help reduce fuel price volatility, and were previously approved by the Commission as being cost-effective for Tampa Electric customers.

In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during the company’s peak periods and spring and fall generation maintenance periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2015?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2015.

Q. Does Tampa Electric anticipate entering into any wholesale energy purchases for 2016 as a result of the Polk Unit 2-5 combined cycle conversion?

A. Yes. In Order No. PSC-13-0014-FOF-EI, issued on January 8, 2013, in Docket 120234-EI, the Commission approved Tampa Electric's determination of need for the Polk Unit 2-5 combined cycle ("CC") conversion, which is to be called Polk Unit 2 CC. The anticipated Polk Unit 2 CC in-service date is January 1, 2017, and its construction timeline requires the Polk combustion turbines ("CT") to be taken off-line from May through November for combined cycle tie-in and testing. This creates a projected need for capacity and energy to meet system reserve margin requirements and ensure operational flexibility. Therefore, Tampa Electric included a 300 MW purchase in the 2016 projection. On August 31, 2015, Tampa Electric issued a market solicitation for proposals to provide the needed firm power. Tampa Electric’s objective is to secure the necessary purchased power for customers at the best possible price.

Q. Does Tampa Electric anticipate entering into any other new wholesale energy purchases for 2016 and beyond?

A. No. At this time, Tampa Electric expects purchased power to meet approximately three percent of its 2016 energy needs. This energy includes contributions from the previously mentioned firm purchases. Tampa Electric will continue to evaluate the short-term purchased power market as part of its purchasing strategy for 2016 and beyond.

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

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The

Florida wholesale power market currently operates through bilateral contracts between various counterparties, and no Florida trading hub exists where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity and standard financial instruments, Tampa Electric has not purchased any financial wholesale power hedges. However, the company employs a diversified physical power supply strategy, which includes self-generation and short- and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric’s risk management strategy for power transactions adequately mitigate price risk for purchased power in 2015?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers’ purchased power price risk. The 121 MW purchased from Pasco Cogen, 117 MW from Calpine, and 160 MW purchased from Southern Power Company are reliable, cost-based call options for power. These purchases serve as both a physical hedge and reliable source of economic power. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continues to evaluate its options in light of changing circumstances and new opportunities. Tampa Electric also maintains a mix of short- and long-term capacity and energy purchases to augment the company’s own generation for the year 2015 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather-related events such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers’ fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's three existing firm purchased power agreements are from dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2015 and 2016.

A. Tampa Electric entered into various non-separated wholesale sales in 2015, and the company anticipates making additional non-separated sales during the balance of 2015 and in 2016. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent.

In 2015, Tampa Electric projects the company's gains from non-separated wholesale sales to be $403,800, which is less than the 2015 threshold of $1,479,981. Therefore, Tampa Electric expects customers to receive 100 percent of the 2015 non-separated sales gains. Likewise, in 2016, the company projects gains to be $59,601, of which customers would receive 100 percent, since the amount is less than the 2016 projected three-year rolling average threshold of $1,532,270.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. However, Tampa Electric does employ a diversified physical power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 150001-EI

September 29, 2015

Q. Please state your name and business address.

A. My name is Simon O. Ojada. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since April 1997.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Science degree from the University of South Florida with a major in Finance in 1991, a Bachelor of Science Degree from Florida Metropolitan University with a major in Accounting in 1994, and a Master of Business Administration with a concentration in Accounting in 1997.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Recovery Clause, Docket Nos. 130001-EI and 140001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Duke Energy Florida, Inc. (DEF or Utility) which addresses the Utility's filing in Docket No. 150001-EI, Fuel and purchased power cost recovery clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 19, 2015. This audit report is filed with my testimony and is identified as Exhibit (SO-1).

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

I reviewed DEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2015. I verified the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2014 to July 31, 2015 to its Hedging Summary by Commodity Reports for 2014 and 2015 to the general ledger. No exceptions were noted.

<u>Gains and Losses</u>

I selected 22 natural gas hedging transactions from August 2014 through July 2015 as a sample. I reconciled the selected samples from the Hedging Details Reports to the third-party confirmation notices and contracts. I reconciled the gains and losses to the Utility's journal entries. I compared the price on the confirmation notice to the price published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

<u>Hedged Volume and Limits</u>

I obtained and reviewed DEF's Risk Management Plan**.** I reviewed the quantity limits and authorizations for all hedged fuel types. No exceptions were noted.

<u>Separation of Duties</u>

I reviewed DEF's written procedures for separation of duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 150001-EI

September 29, 2015

Q. Please state your name and business address.

A. My name is Intesar Terkawi. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since October 2001.

Q. Briefly review your educational and professional background.

A. In 1995, I received a Master Degree of Arts with a major in Communications from the University of Central Florida. In 2001, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Public Accountant and an Enrolled Tax Agent.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Recovery Clause, Docket No. 140001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 150001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 17, 2015. This audit report is filed with my testimony and is identified as Exhibit (IT-1).

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

I reviewed TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2015. I traced the transactions to the general ledger and trade confirmation documents. I verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

<u>Gains and Losses</u>

I traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2014, to July 31, 2015. I selected all gas hedging transactions for September and October 2014 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. I traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. I traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. I recalculated the gains and losses and traced them to the Utility's journal entries for realized gains and losses. I reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. No exceptions were noted.

Hedged Volume and Limits

I reviewed the quantity limits and authorizations. I also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2015, and compared them with the Utility's Risk Management Plan. There were variances for 11 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. All variances were a result of inaccurate forecasting. No further work was done.

Separation of Duties

I reviewed TECO's written procedures for separation of duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF GEORGE SIMMONS

DOCKET NO. 150001-EI

SEPTEMBER 29, 2015

Q. Please state your name and business address.

A. My name is George Simmons. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

Q. By whom are you presently employed and in what capacity?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst I in the Office of Auditing and Performance Analysis. I have been employed by the Commission since November 2013.

Q. Briefly review your educational and professional background.

A. I graduated from Florida A&M University in 2013 and have a Bachelor of Arts degree in accounting.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. No, I have never testified before the Commission.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 150001-EI, Fuel and purchased power cost recovery clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 15, 2015. This audit report is filed with my testimony and is identified as Exhibit (GS-1).

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in this audit.

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2015. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2014 to July 31, 2015. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

<u>Hedged Volume and Limits</u>

We reviewed the quantity limits and authorizations. We also obtained Gulf's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2015, and compared them with the Utility's Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

MS. BROWNLESS: Based upon the previously approved stipulations of the parties for Issue 3J, which is the issue concerning 2014 St. Lucie No. 2 outage, FPL's witnesses Terry J. Jones and John R. Reed and OPC's witness William Jacobs will not be appearing today. Due to the fact that this issue has been deferred, their prefiled testimony and exhibits will not be part of this record.

CHAIRMAN GRAHAM: Okay. Exhibits.

MS. BROWNLESS: Yes, sir. The exhibits listed on the Comprehensive Exhibit List as Exhibits 1, 7 through 18, 19 through 24, 28 through 21 -- oh, I'm sorry -- 28 through 31, 40 through 44, 45 through 49, 68, 70, 71, and 73 have been stipulated by the parties. Staff's exhibits are Exhibits 1, 73, and 75 through 104. We believe that with regard to staff exhibits there are no objections.

CHAIRMAN GRAHAM: Do we have any objections to the staff exhibits, which are 1, 73, 75 through 104? I see no objections. So staff, we will enter those into the record.

(Exhibits 1 through 114 marked for identification.)

MS. BROWNLESS: Thank you. And would also the previous exhibits listed that are party exhibits be entered into the record as well?

CHAIRMAN GRAHAM: So we're going to enter 1, 7 through 18, 19 through 24, 28 through 31, 40 through 44, 45 through 49, 68, 70, 71 and 73 all into the record?

MS. BROWNLESS: Yes, sir.

CHAIRMAN GRAHAM: No objections? We will enter into the record.

(Exhibits 1, 7 through 24, 28 through 31, 40 through 49, 68, 70, 71, 73, and 75 through 104 admitted into the record.)

Additional preliminary matters.

MS. BROWNLESS: Yes, sir. The Office of Public Counsel has filed a motion for reconsideration by the full Commission of Order No. PSC-15-0461 issued on October 23rd. Order No. PSC-15-0461 grants confidentiality to FPUC's responses to staff's second set of interrogatories No. 2A, 2B, 7, 8B, and 9C. That's contained in Document No. 06240-15.

OPC has also filed an objection to FPUC's request for confidentiality for its responses to OPC's first set of interrogatories No. 1 which contain information identical to interrogatories

Nos. 2A and 2B. Subsequent to the filing of OPC's motion, Order No. PSC-15-0504 was issued on October 27th also granting confidentiality to OPC's first set of interrogatories.

Because orders have now been issued covering both FPUC's responses to staff's second set of interrogatories and its responses to OPC's first set of interrogatories and because the material covered is the same, I recommend that these orders be considered together as motions for reconsideration of Order Nos. PSC-15-0461 and PSC-15-0504 by the full panel, and that the parties be allowed to address the Commissioners.

MS. CHRISTENSEN: Mr. Chairman?

CHAIRMAN GRAHAM: Yes.

MS. CHRISTENSEN: At this time OPC is in a position to withdraw our motion for reconsideration of both orders with the agreement of FPUC that the aggregate total for 2015 for legal and consulting fees and the aggregate total for the legal and consulting fee contracts are not confidential, and we're prepared to treat the remainder of the discovery responses as they requested as confidential in this hearing.

CHAIRMAN GRAHAM: Ms. Keating.

MS. KEATING: FPUC is in agreement with what

Ms. Christensen said. We're fine with -- as long as the numbers are treated in the aggregate as opposed to vendor specific, the aggregate number can be used on a nonconfidential basis.

CHAIRMAN GRAHAM: That works for me. Staff?

MS. BROWNLESS: Yes, sir.

CHAIRMAN GRAHAM: So we're moving on to swearing of the witnesses.

MS. BROWNLESS: Yes.

CHAIRMAN GRAHAM: All right. So if you are scheduled to testify in this hearing either today or tomorrow or Wednesday, if I can get you to stand and raise your right hand, please.

Do you hereby swear or affirm that the testimony in this hearing is true? Yes? Thank you.

(Witnesses collectively sworn.)

Okay. Commissioners, I know this is an absolute rarity for me, but I was browbeaten to giving them ten minutes of opening statements rather than five. So since they played so very well together for the first four dockets, I agreed to the ten minutes opening statements. So let's start with Mr. Butler.

MR. BUTLER: Thank you, Mr. Chairman, and I'll try to not use all of my ten minutes.

Good afternoon. I'd like to start by complimenting your staff and the parties for working together well to narrow the scope of issues to be addressed in this hearing. This cooperative effort has resulted in stipulations on most issues, thereby facilitating a much more efficient hearing process.

The remaining issue in dispute for this hearing for FPL is the proposal by Public Counsel that the Commission reverse its established policy on fuel hedging.

In 2002, the Commission approved the stipulation among the IOUs, Public Counsel, and FIPUG which recognized the importance of managing price volatility, directed each IOU to submit a plan annually on how it intended to hedge against that volatility, and establish a framework for utilities to file information that would allow the Commission to review and approve hedging costs for fuel cost -- or fuel clause recovery.

In 2008, FPL asked the Commission to expand and refine the guidelines under which IOU hedging programs would be reviewed and approved. The Commission agreed, stating in its order that, quote, by approving FPL's guidelines, we demonstrate our support for hedging, unquote.

It is those 2008 guidelines under which FPL and other IOUs have been hedging effectively and efficiently for the past eight years. In 2011, the Commission held a workshop to review the 2008 guidelines but concluded that no changes were warranted. FPL's hedging program is designed with one goal, to control the volatility of the fuel costs that our customers pay. FPL's goal is fully consistent with the Commission's hedging policy, and FPL has consistently achieved that goal.

As just one measure of its success, FPL witness Gerry Yupp's Exhibit GJY-7 which I passed out to you shows that the end of year fuel clause over- and under-recoveries have exceeded the Commission's 10 percent midcourse correction threshold just once in the 13 years that FPL's hedging program has been in effect.

In contrast, had FPL not hedged, the 10 percent threshold would have been exceeded nine times during that same 13-year period. You can see the numbers that are shaded in kind of a salmon color on the exhibit.

Against this backdrop of consistent Commission support for an effective IOU implementation of hedging, OPC and other intervenors are now asking the Commission to abruptly reverse course and discontinue its hedging policy. Their stated reasons simply don't justify this about-face.

First, Public Counsel points to what they call hedging losses and suggests that hedging must not be working properly, but this fundamentally mischaracterizes the purpose of hedging.

As the Commission has consistently stated, hedging is done to reduce the impact of market volatility so that the actual cost of fuel does not go up or down as much as market prices. When prices turn out to be higher than expected, this results in paper gains, and when prices turn out to be lower than expected, it results in paper losses. The 2008 hedging guidelines specifically recognize that hedging losses will occur and that they are a reasonable tradeoff for reducing customer exposure to fuel cost increases.

Seeking to game the timing of hedges in an effort to generate gains while avoiding losses would require speculation about future market prices. This would directly violate the Commission's hedging policy, which from the very outset in 2002 said that hedging should be non-speculative.

In the 2008 guidelines, the Commission

stressed that IOUs should not try to, quote, out guess the market in choosing the specific timing for affecting hedges, unquote.

Second, Public Counsel asserts that natural gas prices are low and stable today so that there isn't as much need for volatility control. This assertion simply does not withstand scrutiny.

Mr. Yupp's Exhibit GJY-8 -- and we've got a big copy of it on the board there, I've handed out also a copy that you have before you -- shows that there is simply no consistent pattern in the volatility of fuel price over the past 19 years. Volatility in 2013 was low, but then in 2014 it jumped up to the third highest level over that entire period.

Similarly, volatility was low in 2008 and again in 2010, but was extremely high in 2009. There is no way to look at the volatility in one year and confidently predict what it would be in the following year or years, and certainly there's no neat trend of declining volatility as OPC's Witness Lawton blithely asserts.

Finally, Public Counsel's suggestion that hedging be discontinued because prices are currently low runs directly counter to both intuition and mathematical analysis of price trends. When prices are as low as they currently are, there's not much room for prices to fall farther. Locking in the current low prices offers an opportunity to benefit from an asymmetric probability distribution in which the likelihood of prices rising and thus creating hedging gains exceeds the likelihood of prices falling and producing hedging losses. Therefore, a period of low prices such as we are currently experiencing is certainly not the time to stop hedging.

For these reasons, the Commission should reject the Intervenors' proposal to discontinue its hedging policy. Hedging has and will continue to serve customers well by increasing the stability of their bills, which provides them with greater -- I'm sorry -- greater certainty in budgeting and planning.

That concludes my opening statement, and thank you.

CHAIRMAN GRAHAM: Thank you. Duke.

MR. BERNIER: Thank you, Mr. Chairman. Good afternoon, Commissioners. We would also like to voice our appreciation for the hard work of staff in narrowing these issues and getting us down to a more controlled hearing, but otherwise we would waive opening statements. Thank you.

MR. BEASLEY: Thank you, Mr. Chairman, Commissioners. I echo the comments of counsel regarding the diligence of your staff and the parties to get together and resolve as many differences as they could. As a result, Tampa Electric only has three issues remaining to be resolved in this docket.

First is whether the Commission's supervised program of natural gas financial hedging is in our customers' best interests, the second is whether any changes should be made to that program, and third is whether the company's 2006 risk management plan should be approved.

As our witness on these three issues will testify, Tampa Electric believes that its current hedging program is in its customers' best interest and needs no modification. We also urge that you approve our 2016 hedging risk management plan, and with that we're ready to proceed. And thank you for your time.

CHAIRMAN GRAHAM: Thank you.

MR. BADDERS: Good afternoon, Commissioners. Russell Badders on behalf of Gulf Power. I agree with the statements made by Mr. Beasley and Mr. Butler with regard to hedging, and we also appreciate staff and the parties' efforts to get us down to really that one issue in this docket. But with that, we'll save ourselves eight or nine minutes and we'll waive the rest of our opening.

CHAIRMAN GRAHAM: Thank you.

MS. KEATING: Good afternoon, Commissioners. Beth Keating with the Gunster firm here for FPUC. Unfortunately we do have a few additional issues on the table, but that's certainly no reflection on the diligence of your staff in preparing this case.

As it relates to FPUC, the question that's really before you today comes down to one thing, will FPUC be allowed to continue its proactive approach to pursuing savings for its customers?

FPUC is different. You've recognized that. They're smaller, and you've recognized that too. But in spite of some of the challenges that might come with their somewhat unique circumstances, they've pursued every prudent opportunity available to them to create savings for their customers, and they've done that time and again, created savings for their customers.

The company's witnesses will offer testimony about the specific projects that FPUC has already embarked on that will, in fact, create fuel savings for their customers. Mr. Cutshaw will testify about the value in particular of a proposed interconnect with FPL and what that will mean for FPUC customers after 2017.

You'll also hear about the necessity and value add of the consultants that they've added to their team for these projects. Mr. Young will also provide testimony that the expense associated with these consultants is not being recovered in base rates. As such, you'll hear how without these additional resources, FPUC would not be able to pursue any of these cost saving opportunities.

With regard to the FPL interconnect cost, FPUC's request is not inconsistent with your fuel policy. The Commission's recognized that in certain instances capital projects are recoverable if they're designed to produce fuel savings.

Moreover, consistent with your review of such projects on a case-by-case basis, Commission fuel policy recognizes that there will be occasions where certain similar types of expenses should be treated in a dissimilar fashion.

If ever there were a situation that warranted recovery through the fuel clause, this would be it.

As for the legal and consulting fees, the company's request is consistent with recovery that you've allowed this company in the past and that they've come to rely upon. Moreover, there's no aspect of the company's request that would conflict with the plain language of the settlement approved in the company's last rate case.

In conclusion, you've recognized before that FPUC is smaller and doesn't have the internal resources to handle certain functions without some outside assistance. In this proceeding, FPUC is just asking that you continue to acknowledge FPUC's size limitations and allow recovery for these external resources through the clause. Without recovery, Commissioners, the only ones that will really suffer are FPUC's customers. Thank you.

CHAIRMAN GRAHAM: Thank you very much.

FIPUG.

MR. MOYLE: Thank you, Mr. Chairman. We do have some opening comments that we would like to make, but as others have done, I'd like to start by thanking the other parties and staff for working cooperatively to try to narrow the issues. I'd also like to thank you and your staff for looking at how expert testimony is handled. The Commission previously handled expert testimony in a particular way where there was some qualification, and I understand today we're going to go back to that a little bit, but we'll work diligently to try to make it efficient and effective, but I wanted to preface my remarks with expressing appreciation for that.

The real issue here today for FIPUG and the other consumer parties is to ask you respectfully to discontinue hedging. I think you'll hear from the witnesses who will say hedging is for the customers, we're doing it for the customers' benefit, but you will not hear any customer witness take the stand and say, yeah, this is great, let's continue this, because they won't. The customers are unified in their position, which is it should be discontinued.

And you'll hear some testimony about, oh, we're reducing price volatility. I've said before FIPUG members would rather pay at the pump. You know, there's a lot of things in life that consumers buy, milk, meat, transportation tickets, they pay whatever the price is. Now if it goes up, they don't pay it as willingly and they may make some changes. But, you know, we're in this construct of this hedging that, quite frankly, is not working well when you look at it over the life that it has been put in place. And when I say that, I think there's a couple of important facts.

My understanding is that in 2015, you'll hear from the utility witnesses, that cumulatively over $600 million have been lost as a result of hedging. And some people will say, well, you know what, that's just one year. You've got to take a long-term view of hedging. You can't just kind of look at one year. You've got to look at it over a period of time.

This Commission, in Order No. 07-001 at page 4 that was issued on January 8th, 2008, said, and let me quote, "Hedging programs are designed to assist in managing the impacts of fuel price volatility. Within any given calendar period hedging can result in gains or losses." And this is the next sentence that I really wanted to underscore. "Over time, gains and losses are expected to offset one another." That has not happened with the hedging programs that are before this Commission. And specifically I think you'll hear testimony that since 2002 ratepayers, consumers have lost more than $5 billion as a result of the hedging program, $5 billion.

I know that there's a petition in front of you to build a new power plant, one of the utility has before you. I think the number there is 1.5 billion that they're saying it's going to cost. 1,600 megawatts, 1.5 billion. Quick math, you could do three power plants for the dollars that have been lost since this hedging program got started.

The simple message that we're saying is the consumers have tried hedging. It's not worked to our liking. We would respectfully ask as consumers that you discontinue it. Now somebody may say, well, yeah, you know, you're going to be back if the market prices go up and say what about the hedging program? FIPUG understands that there may be price fluctuations. It may go up. We're okay on paying at the pump, paying those prices, and we would respectfully ask that you not move forward with the hedging program.

There's a couple of other issues that we will have. I'm going to ask as we go through this expert witness process, assuming I'm able to, some questions about a NARUC document. NARUC is an organization; I think, Commissioner Edgar, you are chairing that organization or have chaired it. I know the Commission has participated. I think it's a well-respected group, and I've located a document that discusses hedging that they have put together. And they put together a number of issues and recommendations, and one recommendation that they have that I'll point out is, quote, when activities constantly or consistently produce large losses, they should raise a red flag.

I would venture to say that the hedging activities that have taken place since 2002, which is when this program was kicked off by the Commission, have definitely raised a red flag. And in keeping with Florida, I think it's probably more akin to the double red flag that is put out during hurricanes. The losses are significant. They should be discontinued, and we will pay at the -- pay at the pump.

I'm going to also have a few questions about the Woodford project. That, as you will recall, is a type of hedging that FPL has brought before the Commission. This is the docket where questions related to that are supposed to be asked. And so just because now is the only time I can talk to you and tell you that, I wanted to give you a little heads up that while most of our attention will be focused on hedging and questions related to that, we will have a few questions for Mr. Yupp about Woodford. And we're also going to ask your staff, your Commission staff, your auditor some questions about what's being done to look at Woodford costs or other costs related to these physical hedges in Oklahoma and Louisiana and other places that may be taking place.

So that's a quick preview of FIPUG's questions. And, again, at the end of the day we would suggest that you set in place a plan to discontinue hedging, order the utilities to unwind their hedges. We'll take whatever value we can, credit it to us, and we won't be back saying, oh, we want hedging. I think we're trying to send a real clear message, thank you, we've tried it, it doesn't work, and we don't want it anymore. Thank you.

CHAIRMAN GRAHAM: Thank you, Mr. Moyle.

Mr. Brew.

MR. BREW: Mr. Chairman, as much as I like to have the green light on, I think the plan was to pass the baton down to OPC and then come back.

CHAIRMAN GRAHAM: Okay.

MS. CHRISTENSEN: Good afternoon, Commissioners. Patty Christensen with the Office of

Public Counsel. My comments today are related to the FPUC issues. Mr. Sayler will address the hedging issues upon my conclusion.

First, I would agree with Ms. Keating's comments that FPUC is the smallest of the electric companies that we have; however, I would note it's my belief FPUC is an electric division of a much larger company, Chesapeake.

The issues that we're here to talk about today are Issue 4A related to whether or not the interconnection should be recovered through the fuel clause, and Issue 4B, whether the consulting and legal fees should be recovered through the fuel clause. These issues are not about whether or not these costs should be recovered but rather how these costs should be recovered.

Order No. 14-546 sets forth the types of costs that are eligible or not eligible for fuel cost recovery clause recovery. The order provides a case-by-case exception for fossil fuel-related costs normally recovered through base rates but which are not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, would result in fuel savings to customers.

First, the interconnection. That's

clearly a transmission project. And while ultimately it may provide opportunities to obtain cheaper power, the project is not fossil fuel related. It's transmission. Moreover, the project will not come into service until late 2017, and FPUC cannot buy wholesale power other than from qualified facilities from anyone other than JEA, which is Jacksonville Electric Authority in its northeast division, until the current PPA expires at the end of 2017. So there can be no fossil fuel-related savings for the interconnection in 2016, the year for which they're asking for projected savings.

As you will hear today, some of the requested legal and consulting activities are essentially for exploring new generation opportunities, which is not fossil fuel-related activities and thus are not eligible for clause recovery. Some of the other legal and consulting costs are related to exploring new PPA opportunities, but the company hasn't put forth any evidence that fuel savings are attached to these individual activities.

Order No. 14-546 also states that fuel procurement, administrative functions, even though they are fossil fuel-related costs, are more appropriately recovered through base rates. Most, if not all, of FPUC's requested legal and consulting costs are essentially procurement administrative functions and thus would not be eligible for clause recovery.

And while specific legal and consulting fees have been allowed to be passed through the fuel clause for specific PPAs when fuel savings were readily determinable in the past for this company, that's not the case here. These fees are related to generic fuel procurement and administrative type activities and are not specific projects, and FPUC has not made the case that specific fuel-related savings will be achieved.

So we are only asking that these costs be disallowed for fuel cost recovery. We believe these are the types of costs that are appropriately recovered through base rates. Thank you.

CHAIRMAN GRAHAM: Mr. Sayler.

MR. SAYLER: Good afternoon, Commissioners. Erik Sayler with the Office of Public Counsel on behalf of the citizens of the State of Florida. OPC would like to echo the working with all the parties, staff to streamline this process. I'd also like to thank the utilities and the parties for agreeing to stipulate to a number of OPC discovery responses into the record, which greatly streamlined my cross-examination today.

And I would like to start out by saying the financial hedging of natural gas should be discontinued or suspended for the time being. It only serves to add unnecessary costs to the price customers pay for fuel on their utility bills.

When this Commission modified the hedging programs in 2008, it was the expectation that hedging gains or losses would offset over time. It is now 2015, and hedging losses have continued to mount in a significant way.

According to the testimony and exhibits of OPC witness Mr. Lawton, natural gas prices and price volatility have been decreasing, and that trend is expected to continue for the foreseeable future. Thus, the reasons and the market conditions justifying natural gas financial hedging in 2002 and 2008 have fundamentally changed and no longer justify the continuation of these programs.

Utility regulatory commissions in Nevada and Kentucky have also recognized these changes in the natural gas markets and have ended the financial hedging of natural gas within their borders. A review of the evidence submitted by Witness Lawton and Noriega show that the attendant costs of hedging outweigh any benefits gained from the mitigated fuel price volatility.

We maintain that it is the utility's burden of proof to demonstrate that customer benefits received by continuing natural gas hedging programs outweighs the billions of dollars of hedging costs paid by our customers, our clients since 2002. The evidence in this docket shows that the utilities have failed to meet this burden.

First, the current conditions of natural gas markets and the outlook for future natural gas supplies and prices are demonstrably different in 2015 than they were in 2002. These differences allay the customers' concerns regarding the potential adverse impact of price volatility and price spikes caused by weather or supply disruptions on their bills.

Second, while there's no guarantee that temporary price spikes and volatility will not recur, the Energy Information Agency's annual energy outlook forecasts show a plentiful supply and availability of natural gas along with stable economic conditions. Since 2011, the last time the Commission held a workshop, no natural gas reserves alone have increased by 31 trillion cubic or by 10 percent over and above the EIA's 2011 annual energy outlook.

Third, the current natural gas market forecasts demonstrate that the prior justifications and reasons for past natural gas hedging efforts -- mitigating price volatility, threats to market supply, other factors influencing demand -- these things are no longer available as reasons to support the need to continue natural gas financial hedging activities.

Fourth, with regard to the fuel price volatility, volatility is trending down, as Mr. Lawton demonstrates in his exhibit, Mr. Lawton's Exhibit 2. Increases in the price of natural gas are projected to be gradual and steady in the long run. Moreover, hedging aside, there is a cost-free way to mitigate customer fuel price volatility. The Commission's annual fuel adjustment clause proceeding and midcourse correction rule already effectively, efficiently, and economically mitigate against and reduce fuel price volatility experienced by customers on their monthly bills. The Commission's annual resetting of the fuel factor as opposed to the semi-annual or monthly resetting which was done in the past by this Commission has the effect of smoothing out price volatility within a 12-month period and adequately allows the customers -- small homeowners to commercial customers to the big industrials -- to adequately budget for their electrical costs.

Thus, the price of natural gas can go and down within that 12-month period, volatility, without impacting the customers' monthly rates within that one-year period. Combine the volatility smoothing effect with the midcourse correction rule, which requires at least a 10 percent change in the fuel factor to be triggered, and then you have an effective, cost-free way to mitigate fuel price volatility experienced by the end-users, my client, the customers.

Some may call hedging and insurance policy to protect against fuel price volatility. In that analogy the premium paid for this hedging insurance is the cost paid above and beyond the market price of natural gas. Customers understand that within any given calendar period hedging can result in gains and losses; however, customers, the utilities, and the Commission were all under the expectation that, and I quote from a prior order, quote, over time hedging gains and losses are expected to offset one another, end quote.

To date the customers have paid approximately $6 billion in premiums for this hedging insurance. As a result, the gains and losses are nowhere near to offsetting one another, and there's no expectation that the utility's hedging programs can dig themselves out of the $6 billion hole. Therefore, if hedging is an insurance policy against fuel price volatility, we're asking this Commission to cancel this policy.

In conclusion, financial hedging no longer makes dollars and "sense" in the current natural gas market, not now and not for the foreseeable future. It is no longer reasonable or prudent to allow hedging costs to be passed along to Florida customers through the fuel clause. The opportunity costs of hedging vastly outweigh the hedging benefits, and the facts and evidence submitted during this hearing will demonstrate that hedging should be ended in Florida. Thank you very much.

CHAIRMAN GRAHAM: Thank you, Mr. Sayler.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman, Commissioners. Good afternoon. I won't take anywhere near ten minutes. I want to start by thanking all the parties, and particularly the extraordinary diligence of your staff in bringing in so many stipulations and excusals of witnesses in for a very effective and smooth landing. It's a great job all around.

I do have a very brief remark about FPUC's issues 4A and 4B and then also some similarly brief remarks about hedging.

Regarding FPUC's request to recover really non-fuel transmission project and consulting fees through the fuel clause, we seriously question the assertion that it would only be customers who would be harmed by this. If Florida Public Utilities Company is suggesting that the company will not do this project which they facially believe is appropriate and cost-effective if they don't get recovery through the fuel clause, that's flat out imprudent and contrary to customers' best interests. If it's a prudent investment, the company should make the investment, put the investment in rate base where it belongs, recover it through base rates where it belongs, where the recovery belongs accordingly and appropriately. If they have to have a rate case, they have to have a rate case. That's how this regulatory system works.

With regard to hedging, the Retail Federation joins with our fellow consumer parties in agreeing that the Commission should suspend or terminate natural gas financial hedging by the IOUs. The Commission's fuel and purchase power cost recovery proceedings, including true-ups and midcourse corrections, effectively and economically mitigate and reduce fuel price volatility. Accordingly, the Commission should deny the IOUs' risk management plans, that's the real issue on the table in this docket, related to natural gas financing hedging and should suspend or terminate that hedging.

The Commission should direct the IOUs not to enter into any new or additional financial hedging transactions until and unless an IOU can demonstrate that financial hedging transaction would at least have a high probability of providing net benefits to customers. That hasn't been the case over these 13 years. Thank you very much.

CHAIRMAN GRAHAM: Thank you, Mr. Wright.

Mr. Brew.

MR. BREW: Thank you, Mr. Commissioner. I'm going to confine myself just to the hedging issue. Really to hedge or not to hedge isn't a slam dunk, black and white issue. It's a question of what are the risks, what are the costs, and what's the value to consumers? And what you saw in OPC's testimony are -- is a -- it's a litany of facts that are pretty well accepted now, which is declining and far more stable oil and gas prices for the simple reason that we've moved from a period of relative scarcity of those where we're going to keep increasing reliance on both both in Florida and throughout the country to a period of abundance where Mr. Sayler just mentioned the really astounding amount of natural gas that's now recoverable. NYMEX today was under $2 a million per Btu for the first time that I can recall in decades.

So what we're really talking about is not crystal ball gazing on whether we think gas is going to jump or go down but whether or not there's value to consumers anymore. And what you is the slate of consumer representatives here collectively saying that we don't see the value in it anymore.

Also what we're really talking about is effectively regulatory lag, which you talk about all the time in rate cases, which is how long it takes to adapt a regulatory policy to change circumstances. Now in this case the dramatic change in circumstances with respect to domestic oil and gas supply has happened quickly, far faster than anybody anticipated, but it is the new reality.

What you had is things that have happened only in the past couple of weeks that you would have never imagined a short time ago. Last week the White House did a budget agreement with Congress that includes selling a significant amount of oil from the strategic reserve to raise money because it didn't to maintain that much reserve anymore. You have a House bill approved in October to end the longstanding ban on export of crude oil produced in this county. Again, circumstances have changed.

I represent a large consumer that is very concerned about volatility in their electric bill, but we do not see the value in continuing the hedging practice. I think actually Duke's witness McCallister put it well in his rebuttal where he said this is not -- it's really a policy call for the Commission. We agree. But the fact is that the costs of hedging are not paper costs. They're real costs to consumers that have been cataloged in OPC's testimony and they don't provide the value, and for that reason we join with the other parties in recommending that you deny the risk management plans and have the companies move forward in a fashion that reflects the world we're actually in today. Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

All right. So those are all the opening statements. Staff, are we -- I guess we're to witnesses.

MS. BROWNLESS: Yes, sir.

CHAIRMAN GRAHAM: All right. First witness.

MR. BUTLER: FPL would call Mr. Yupp.

Whereupon,

GERARD YUPP

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

EXAMINATION

BY MR. BUTLER:

Q Mr. Yupp, were you sworn a few minutes ago at the mass swearing in?

A Yes, I was.

Q Okay. Would you please state your name and business address for the record.

A Yes. My name is Gerard Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida.

Q Okay. By whom are you employed and in what capacity?

A I'm employed by Florida Power & Light as Senior Director of Wholesale Operations.

Q Okay. Have you prepared and caused to be filed in this proceeding on March 3, 2015, six pages of prefiled direct testimony with attached Exhibit GJY-1?

A Yes.

Q Okay. And have you prepared and caused to be filed in this proceeding on April 7, 2015, four pages of prefiled direct testimony with attached Exhibit GJY-2?

A Yes.

Q Have you prepared and caused to be filed in this proceeding an Exhibit GJY-3 on August 4, 2015, which is FPL's 2006 Risk Management Plan?

A Yes.

Q Okay. Have you caused to be prepared and filed in this proceeding on August 14th, 2015, Exhibit GJY-4, FPL's Hedging Activity Report for January through July 2015?

A Yes.

Q And finally have you prepared and caused to be filed on September 21, 2015, 29 pages of supplemental direct testimony with attached Exhibit GJY-5?

A Yes.

Q Okay. Do you have any changes or revisions to your prefiled direct testimonies and exhibits?

A No, I do not.

Q Okay. With those changes -- I'm sorry. You don't have any changes. If I asked you those same questions contained in your direct testimonies today, would your answers be the same?

A Yes, they would.

Q Okay. Mr. Yupp, FPL filed a notice on October 14, 2015, that you will testify as an expert in this proceeding with respect to several subject matters, including natural gas financial hedging projections and calculations associated with gains and losses for asset optimization activities, projection and calculation of costs associated with asset optimization activities, projection of fuel costs, and projection of physical hedging costs. Is it your intent to testify as an expert on those topics?

A Yes.

MR. BUTLER: Mr. Chairman, at this time I tender Mr. Yupp for voir dire by any party that wishes to inquire as to his expertise on these topics.

CHAIRMAN GRAHAM: Thank you.

All right. Commissioners, this is the part that we're trying to figure our way through, so it's going to be -- especially the first time it's going to be kind of interesting.

What we're going to do, there's two of the parties that are questioning the expertise, which is FIPUG and Florida Retail, so we are going to allow them to question the witness, and then we will allow the utility, in this case Florida Power & Light, to respond to each one of those -- I'm sorry -- to redirect on each one of those challenges.

And then I guess I will be asked, is that correct, staff, to make a determination? And if I agree with the objection, then we'll go through and figure out which part of the testimony that we would strike. If I don't agree with the objection, then we will move on as normal with the witness as far as with his five-minute summary and then the cross-examination.

Please note as we're going through this, there's no need to ask the same questions you're asking during the challenging and then go back and ask the same questions again during the redirect -- not the redirect but during the cross-examination.

Okay. Mr. Moyle, you are up.

MR. MOYLE: Thank you. Thank you, Mr. Chairman.

VOIR DIRE EXAMINATION

BY MR. MOYLE:

Q Good afternoon, Mr. Yupp. I just want to focus in on a couple of the areas that are set forth in the notice that Florida Power & Light filed with respect to your areas of expertise. You've seen that notice, right, or no?

A I don't recall if I have or haven't.

Q Well, I don't want to put you in an unfair spot. It says that you have expertise in natural gas, financial hedging. Is that right?

A Yes.

Q And it says, it goes on and it says some other things. It says you have expertise in the projection of physical hedging costs?

A Yes.

Q What are -- what's the projection of physical hedging costs?

A You're referring to projections and calculations associated with the gains and -- or, excuse me. I'm seeing -- it says natural gas financial hedging projections and calculations associated with gains and losses for asset optimization, projection and calculation of costs associated with asset optimization, and projection of fuel costs, and projection of physical hedging costs.

Q Right. So what you just read was from the notice that I just asked you about; right?

A Right.

Q So you do have a copy of it?

A Yes, I do.

Q Okay. And what I asked you about was the last phrase, "projection of physical hedging costs." Okay. So tell me what your expertise is in the projection of physical hedging costs, or just tell me what physical hedging costs are and then tell me about your expertise in it.

A The physical hedging costs in this aspect would have been related to the Woodford Gas Reserves Project, which are included in our projection filing for 2016.

Q Okay. So you're saying that you had projection of those costs?

A Yes.

Q And then what opinions do you have with respect to those costs --

A I --

Q -- that you're going to share with the Commission?

A I'm not sure what you mean by "opinion." I don't -- the costs that we're projecting for 2016 are what they are. I do have an opinion as to how those costs are, I will say, how those costs are in line with what we originally projected during the gas reserves hearing.

Q Okay. So did you prepare these projection of these costs?

A I did not.

Q Okay. Who did?

A That would have been done within our accounting group, I believe.

Q Did you put any inputs into them? Did you have any inputs into these projections?

A The input that I have into the projections would be related to the transportation cost to deliver the gas from the Woodford project to the Southeast Supply Header pipeline. And just going back to when you asked who would have been involved, I think probably various groups involved in the projections of those costs, everybody from accounting to finance and individuals within the division that I work that are familiar with the Woodford project.

Q Okay. So I'll tell you, my recollection of some of the testimony in that Woodford was FPL, y'all said to the Commission essentially, hey, we're at $3.50 of the production costs. I may be off a penny or two on that. But essentially 3.50, and your expert witness from Texas at the time said, I think these are pretty stable. My sense was, is that you were relying on PetroQuest because it was their costs that you were agreeing to pay. Do I have that wrong?

A I'm not sure I follow what your question is. We were lying about what?

Q You were relying. Weren't you relying on PetroQuest and their production costs for Woodford? Like, you're paying PetroQuest their production costs.

A Yes. Correct.

Q Wasn't that about $3.50?

A I think in year one, if I'm not mistaken, on Exhibit SF-8 the year one effective cost delivered to Perryville was, I believe, $3.48.

Q Okay. And so today you're going to testify to this Commission, you're going to give them an update on those projections?

A If I'm asked to give an update, I certainly will give an update, yes.

Q Okay. Well, I'll probably ask you that. But I guess what I'm trying to explore is that seems to me like a fact more than expertise. Do you understand --

A Yes.

Q -- the distinction between facts and opinion with respect to expert testimony?

A Correct. I agree with you, that is a fact.

Q Okay. And so when you are saying, oh, I'm an expert in projection of physical hedging costs, that doesn't relate to what the PetroQuest people are charging; correct?

A That's correct.

Q So what does it relate to?

A I am sponsoring the physical hedging costs that are included in our 2016 projection. I am sponsoring the facts of what those estimates are.

Q Have you ever given advice to a third party about hedging positions?

A I have not, no.

Q And when you say -- this document says projections and calculations associated with gains or losses for asset optimization activities, those are facts more than opinions; correct?

A That's tough to answer as far as whether they're more facts than opinions. From an asset optimization standpoint there does have to be a certain level of opinions that go into that based on historical data, based on market conditions currently in order to make projections that get included in the projection filing. So I'm not sure how to answer that. I think there's both.

Q Did you make the projections that you're referencing?

A I did.

Q Okay. So there might be some expertise on projections, but with respect to calculations, that's just doing the math; right?

A Calculations are math, yes.

Q Okay. And in your rebuttal testimony you get into a little bit of the back and forth about should hedging continue or not continue; correct?

A Correct.

Q Okay. And if I ask you questions, policy questions about hedging and why you think it's good or why you think it's bad, would you be comfortable answering those questions?

A Yes.

Q Okay. And have you ever been asked questions like that by your company.

A Of whether I believe we should continue hedging or --

Q Or not continue hedging?

A No, not specifically to continue hedging or not continue hedging. No.

Q Have you ever been asked by anybody until today questions about natural gas financial hedging with respect to what your opinion, what your area of -- can you give me your expert opinion on something related to natural gas financial hedging?

MR. BUTLER: Do you mean the general subject of it?

MR. MOYLE: Yes.

THE WITNESS: I guess I can tell you that -- the 2008 guidelines that this Commission approved, I had a lot to do with writing those guidelines. So I think by default, yes, I've been asked my opinion about hedging.

BY MR. MOYLE:

Q Did you come up with those guidelines, or was that Mr. Forest or others?

A No. I had a large part in creating those guidelines.

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

CHAIRMAN GRAHAM: Mr. Wright.

MR. WRIGHT: I don't have any voir dire for Mr. Yupp. Thank you.

CHAIRMAN GRAHAM: Redirect.

REDIRECT EXAMINATION

BY MR. BUTLER:

Q Mr. Yupp, briefly would you describe your involvement with hedging since the Commission adopted its first hedging order in 2002 for FPL?

A Yes. Commissioners, I've been involved in hedging, as Mr. Butler stated, since inception back in 2001, 2002. I have basically provided or served in the role of fuel witness for FPL since that time period. I have been involved with all discovery requests and interrogatories and audits that take place on hedging. I have filed testimony in this docket or in the fuel docket 16 times, direct testimony. I've filed hedging testimony 13 times. I had a large role in the audit that was conducted back in 2008, if you'll recall, on the investor-owned utilities' hedging practices.

So I have really been a -- I don't want to use the word instrumental, but I have been close to the hedging of Florida Power & Light or involved in the hedging that Florida Power & Light does since inception of the program.

Q Mr. Yupp, do you have regular involvement in overseeing FPL's hedging program?

A I do not specifically oversee it. The hedging transactions are conducted by a group within my division. But, yes, I am involved in the writing of the risk management plans in determining hedge levels and all of the related matters to hedging.

MR. BUTLER: Thank you.

That's all the redirect that I have, Mr. Chairman.

CHAIRMAN GRAHAM: Mr. Moyle, what exactly IS your objection?

MR. MOYLE: Well, with respect to the areas for which the notice of filing was made of October 14th, 2015, I think the witness himself acknowledged that he doesn't have any expertise with respect to the projection of physical hedge costs as it relates to extracting natural gas from the ground. I think he indicated his area of expertise may be limited more to transmission. So I would seek that if he is going to be an expert, that it be limited to projection of physical hedging costs related to transmission. That's one point. I don't know if you want to kind of take these one at a time or --

CHAIRMAN GRAHAM: How many points do you have?

MR. MOYLE: Two.

CHAIRMAN GRAHAM: Let's take the second one.

(Laughter.)

MR. MOYLE: So the category of natural gas financial hedging, I asked him, you know, have you talked to people, have you given advice on natural gas financial hedging, and I think he said, no, he's had some conversations. Mr. Butler asked him, "Do you oversee hedging?" And he says, "No, I don't oversee hedging." He developed the guidelines. He said, "Well, I filed all this testimony," but, you know, candidly the testimony is factual testimony. It's like how did the hedging program work out last year? Oh, we made money or we lost money or, you know. It doesn't really get into areas of expertise. It's more factual, so I don't think it's appropriate to accept him as an expert in natural gas financial hedging.

I mean, an expert, respectfully in my judgment, would be someone who I spent ten years with Morgan Stanley in charge of their energy markets, and financial hedging was part and parcel of that. So those are the two points. One, I think with respect to the projection of the physical hedging costs that's limited to transmission and, secondly, with the broad category of natural gas financial hedging, I don't think he's established that he has expertise in that area.

MR. BUTLER: Mr. Chairman, may I respond?

CHAIRMAN GRAHAM: I don't think so. Staff?

MS. BROWNLESS: It's a new process for us.

CHAIRMAN GRAHAM: Okay.

MR. BUTLER: Briefly just to Mr. Moyle's two points. With respect to the physical hedging, you know, Mr. Yupp's role, as the interchange indicated, is to present simply the facts of what FPL's projections of those costs are. I think he's fully qualified to do that. I also don't think there's really much of an issue about the admissibility of testimony on those facts because he's simply testifying to them as facts and you can characterize it as an expert witness on that or a lay witness. Either way he's testifying to facts.

And as to his expertise in natural gas financial hedging, you know, Florida's evidence code recognizes explicitly that one's experience as well as education and particular professional roles can be a basis of expertise. Mr. Yupp has testified that he has, you know, as much experience as anybody in the state on Florida's hedging, excuse me, program, not only its implementation but, you know, the development of the guidelines under which we are currently operating. So he's currently -- or clearly qualified in that regard.

And finally I would note that, you know, this is an administrative proceeding. This is not something that is limited to strict rules of evidence. You take testimony when it is the type of information that a reasonable person would use in making decisions for him or herself. I think Mr. Yupp has clearly demonstrated that he has the sort of experience that would provide you useful testimony in reaching your decisions. Thank you.

CHAIRMAN GRAHAM: Mary Anne, of course, you knew I was coming this direction.

MR. MOYLE: Can I just -- I know this is new, but just -- and I don't think we'll do this on all of them.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: One point, I think Mr. Butler and I may actually agree on the first point because he just said he's going to present facts about the projections. He didn't say, no, I want his opinion to go in. You know, it seems that we don't have a real disagreement about the projections of the physical hedging costs because his own words are they're facts.

So my impression is expert opinion is opinion, you know, like should hedging continue or discontinue, and here are the reasons why. That's kind of a policy call and someone shares their opinion. So I think that point should be resolved kind of in FIPUG's favor.

And then, you know, and then the second

one on the financial hedging and the point about, well, it's an administrative proceeding. It is an administrative proceeding and there is a different evidentiary code, but it's also a proceeding in which disputed issues of fact are determined, and the evidence code is a pretty good barometer to help determine issues of fact. I mean, it's not discarded out the -- you know, left in the hall when we have these proceedings. It's something to look to. And if you're going to make a finding on an expert opinion testimony, respectfully it should be someone that has well demonstrated their area of expertise. So thanks for giving me the chance to make those two points.

CHAIRMAN GRAHAM: Mary Anne.

MS. HELTON: I actually agree with Mr. Butler that, you know, we are in an administrative proceeding here. We are not in a civil proceeding or circuit court where the rules of evidence should be strictly applied. And Chapter 120 has some guidance for you with respect to how to look at evidence in an administrative hearing, and I might add an administrative hearing where you're performing a ratemaking function. And that is, "Irrelevant, immaterial, or unduly repetitious evidence shall be excluded, but all other evidence of a type commonly relied upon by reasonably prudent persons in the conduct of their affairs shall be admissible, whether or not such evidence would be admissible in a trial in the courts of Florida. Any part of the evidence may be received in written form and all testimony of parties and witnesses shall be made under oath."

I believe as we're going through the testimony that you will be able to discern whether you think there's fact testimony or opinion testimony and give it the weight that it's due based on the testimony, the direct testimony that's permitted and the cross-examination by the witnesses. I don't know that I've heard anything here today that would make me recommend to you to not find Mr. Yupp an expert, but it's within your discretion.

CHAIRMAN GRAHAM: Well, then I guess the question I have to you, and this goes right back to what Mr. Butler was saying, if we're using, quote, the reasonable man standard, then why are we even voir diring experts? That was the question.

MS. HELTON: Because Mr. Moyle has asked us to.

CHAIRMAN GRAHAM: Did you feel that bus go over you?

MR. MOYLE: Yeah, but I got big shoulders so, you know. It's not the first bus that I've encountered.

I'm happy to -- I'm happy to respond if it would be helpful.

CHAIRMAN GRAHAM: Please.

MR. MOYLE: So I recognize -- I've practiced here for a long time. My practice is also in other tribunals, including the Division of Administrative Hearings, and I think that it is helpful -- you know, if I were putting myself in a position of a decision-maker, I think it would be helpful to me to know, you know, who an expert was and who a fact person was and have it be clearly articulated and not all kind of mushed together. And I know I think some, you know, some of y'all, you know, there's an expert. I'm -- somebody takes the stand and they say I'm an expert, I'm here today testifying, and, you know, an expert related to -- I don't want to start calling out names of people that you, you know, you regularly see, but I will call out a FIPUG witness, Jeff Pollock. He appears regularly before you all. Rarely does he come in and talk about, you know, the facts. He says here's what I believe as an expert and shares with you his opinion.

And, you know, opinion evidence is designed to help you all if you are not clear about a matter of policy, as I understand it. I mean, the facts are the facts and you can -- those are balls or strike calls that you make, but the opinion testimony typically is provided on hearings that are really complex that help the tryer of fact understand something. So that is the distinction that I see.

But I think as a matter of practice here, it could be improved if someone were testifying clearly and they said I'm testifying as an expert in these areas, one, two, three. Here's the basis for my expertise. I spent 20 years doing this and now I'm an expert, and here's my opinion and I'm sharing it with you. I think you should continue hedging for all these reasons, and it's just clear.

I mean, right now we're in this situation where it's unclear, and I'm trying to work to try to make it a little more clear, which I understand is consistent with how you all did it, you know, years ago. I don't think I was here. I have voir dired before a couple of times, but I don't -- my understanding is many years ago you all had a more formal process for expert opinion testimony and fact opinion testimony.

So that's sort of the reason for it. I

don't know that, you know, we're going to get it all kind of squared away in this proceeding, and I'm going to, you know, probably tread easily. This was the first time we've done it. But my desire is to try to make it a little more clear because I think not only will it help parties, I think it'll help the Commission at the end of the day.

CHAIRMAN GRAHAM: Mr. Butler.

MR. BUTLER: Let me just respond briefly, Mr. Chairman. I've been practicing here a pretty long time, 36 years now, and frankly the process that we've used very consistently over that time of simply having the witnesses appear, identify what their background is, it's quite common that once the witness's testimony has been inserted into the record and they are cross-examined for parties, including FPL, to question people's, the extent of people's expertise and experience in particular areas, and we believe that the Commissioners take that into account when they decide how much weight to give that testimony. In other words, essentially the process that Ms. Helton was describing earlier.

I think that the add-on of this, frankly, artificial process of, you know, voir dire being incorporated or imported from civil litigation practice here isn't adding anything to your understanding of what the witnesses do and don't know on topics. You could get the same thing from the process that's been used for years.

And, you know, with respect to this particular witness, I mean, obviously what Mr. Moyle is setting up here is the idea that if you hire somebody from the outside, they go around the country testifying all the time, that makes them an expert and somehow somebody like Mr. Yupp isn't. I would turn it around. I mean, often the people who come in from the outside have limited exposure to the specifics of this jurisdiction and the particular utilities they're talking about. I think Mr. Yupp on this issue has demonstrated it's maybe not quite 20 years, but it's 16 years' worth of testifying in this area.

So to me, that's the sort of thing that would be very important for you to hear that sort of person's views as well as their presentation of the facts. And I think it's very easy to incorporate that process of exploring the extent of people's true knowledge and expertise into simply the cross-examination of the witnesses once they are tendered for cross. Thank you.

CHAIRMAN GRAHAM: Well, this is where it becomes a little difficult for me. The two challenges that FIPUG had, the first one -- can I get you to restate that first one?

MR. MOYLE: Sure. The first one, and, again, I'm working off what was filed by FPL.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: He professes projection -- expertise in the area of projection of physical hedging costs. Okay. And all I'm saying there is based on the questions I think he admitted that he just takes the PetroQuest production numbers and that that's a factual number. So he doesn't independently know, he hasn't gone out and talked to a bunch of wildcatters in Oklahoma to figure out their production costs. He's just taking a number from PetroQuest and saying that's part of my calculation.

So I don't think he's even suggesting he has expertise in physical production costs. He said, I have some expertise in transmission, how much it's going to cost to move the power from Oklahoma to Florida, as I understood it. So on that point, I'm just saying that his area of expertise be limited to transmission and not include production costs as it might relate to extraction and production of the natural gas coming out of the ground.

CHAIRMAN GRAHAM: And, Mr. Butler, if I -- unless I heard you incorrectly, and please let me know, you basically agreed with what he just said. You restated it and you said that he's just -- he's now giving facts and that's all he's doing in this part. Is that correct?

MR. BUTLER: He is giving facts. You know, we were asked to identify areas that our witnesses could testify expertly in. I think Mr. Yupp, if he were asked his opinions on those subjects, he could provide them. But what he is testifying to are just what the facts of the projected numbers are. That's all that's in his testimony, and it's all that we are presenting to you for approval. It's simply what the dollars are that would be included in the 2016 fuel factors on a projected basis subject later to true-up to the actuals for the Woodford project production costs.

And I struggle here because, frankly, both experts and lay witnesses are entitled to testify to facts. You don't have to stop testifying to facts because you're an expert and you aren't prohibited from testifying to them if you are a lay expert -- or a lay witness. So I guess in some respects I'm not quite sure what Mr. Moyle's objection to Mr. Yupp testifying about the facts of the projected production costs for the Woodford project are. I think he is clearly eligible to testify to those either as an expert or a lay witness.

MR. MOYLE: And I don't object to him testifying as a fact witness. I do object to him testifying as an expert witness because he says he doesn't have expertise in that area.

MS. HELTON: Maybe this might be one of those areas where it would be helpful to know specifically are there areas of the testimony for which you object to Mr. Yupp testifying, the testimony that's already been prefiled?

MR. MOYLE: I have a bunch of stuff marked in rebuttal, but he didn't file anything in his direct with respect to, you know, production costs that I've seen with respect to the Woodford.

MR. BUTLER: He has a small section of his testimony that goes to that, but, as you say, it's facts. It's saying here's what the projection is.

MR. MOYLE: So respectfully I think no objection to him testifying as a fact witness. So if we want to kind of move beyond this, it seems like the easy solution is he'll be a fact witness with respect to

Woodford, not with respect to expertise on production costs, unless Mr. Butler wants me to ask him what did you do? Did you go look at other wildcatters and what their production costs were, and get into areas that I don't know that the witness is prepared to testify to.

MR. BUTLER: Not only that, areas that are not relevant to the issue that's identified in this proceeding. And I think Mr. Yupp is clearly in a position to testify to the only issue that is, you know, active in this proceeding or open for scrutiny in this proceeding, which is what are the projected costs for the Woodford project that will be included in the 2016 fuel factors. I think whether you characterize that as expertise or lay testimony, he is clearly here, he's prepared to -- he's prefiled testimony and can support that testimony on what those projected costs are.

CHAIRMAN GRAHAM: Mr. Moyle, give me one or two examples of testimony you're talking about that is expert testimony that you're looking to challenge or strike.

MR. MOYLE: So -- and this relates to the first point with respect to the natural gas, you know, his expertise in natural gas hedging. I was going to suggest that on his October 9th, 2015, testimony that page 6, starting at line 7, through page 7, going to line 11 --

CHAIRMAN GRAHAM: Wait a minute. I need to get --

MS. HELTON: Is that in rebuttal or the direct?

MR. MOYLE: That's rebuttal.

MS. HELTON: Okay. I guess I'm confused. Isn't Mr. Yupp on the stand right now only for his direct testimony?

CHAIRMAN GRAHAM: But I think we're voir diring him for both. Is that correct?

MR. MOYLE: That was my understanding.

MS. HELTON: Okay. I was -- somehow I missed that part.

CHAIRMAN GRAHAM: Okay.

MR. SAYLER: What's the page numbers again?

MR. MOYLE: This is on his rebuttal, page 6, starting at line 7, and it goes through page 7, line 11. And then I also have starting on page 8, line 16 --

CHAIRMAN GRAHAM: Wait. Let's start with the first one. Go back. What's the page?

MR. MOYLE: Page 6, line 7. The question is "OPC Witness Lawton refers to significant losses from hedging numerous times in his testimony. Is this a fair basis to assess the success of FPL's hedging program?"

That question calls for an opinion. That is not really a factual, you know, question. Like, how much did you lose? That would be factual. This is an opinion. And he's asked about Mr. Lawton's reference to significant losses and says is that fair?

So, again, to the fairness point, I think that's an opinion that's inappropriate given his admitted lack of being asked about hedging by his company or others.

MR. BUTLER: I think that is a gross mischaracterization of Mr. Yupp's testimony on his expertise. Look, this is asking what would be a fair basis to assess success of FPL's hedging program. As Mr. Yupp testified, he was firsthand involved in, you know, developing and then presenting to this Commission the very guidelines by which hedging programs are currently judged in Florida. To me it's hard to imagine somebody being more directly expert in that topic of what is the measure of success than what Mr. Yupp has as a background.

CHAIRMAN GRAHAM: Mr. Moyle, do you have another question?

MR. MOYLE: No. I mean, we've covered that. I asked him the questions, so the record is, I think, clear on that point. I do have a couple of other areas

I was going to --

CHAIRMAN GRAHAM: That's what I mean, another area.

MR. MOYLE: Yeah.

CHAIRMAN GRAHAM: Your mike.

MS. BROWNLESS: Oh, I'm sorry. I'm sorry to interrupt, but on page 6, it's line 7 through what line that you object to?

CHAIRMAN GRAHAM: Nineteen.

MS. BROWNLESS: Okay. It's that one question only?

MR. MOYLE: Right.

MS. BROWNLESS: Thank you.

MR. MOYLE: Ready for the next one?

CHAIRMAN GRAHAM: Yes.

MR. MOYLE: Page 8, line 6, he's asked, "Do you believe that it is realistic as Witness Lawton suggests on page 53 of his testimony to discontinue hedging now and to revisit the topic if circumstances change substantially in the future?" And then he gives again opinion testimony related to that all the way down through line 22. So I identify that as pure opinion testimony.

CHAIRMAN GRAHAM: Mr. Butler.

MR. BUTLER: And this relates to one's experience in actually having to place hedges and what is available in the way of hedges, when you can start, when you can stop with a program, and I think that Mr. Yupp is eminently qualified to know what is -- realistically can be done or can't be done in terms of protecting against volatility that suddenly arises as a result of, you know, changes in the gas prices if you were to discontinue and then had to restart the program.

This goes directly to the issue of how one actually implements a hedging program, which is something that Mr. Yupp has considerable experience in doing.

CHAIRMAN GRAHAM: Mary Anne.

MS. HELTON: Yes, sir.

CHAIRMAN GRAHAM: I guess clearly I disagree with Mr. Moyle on this first one because it's asking specifically about your feelings about Florida Power & Light, which this guy has been the guy for Florida Power & Light from day one.

When it comes down to number two or his second challenge is where I guess I hit a bit of a snag, and I guess if any fellow Commissioners have any questions or comments, I welcome them because we're trying to feel our way through this as we're doing this. I'm asking you -- this -- the problem you run into is, and this goes right back to the same questions of voir diring, if we can accept the testimony of just a layperson, then why do we have to determine if it's an expert or a layperson because we're just going to give it -- or we can just go ahead and say you're an expert for these first nine issues, but this last one you're just a layperson and we'll just give it the weight that it deserves.

I mean from what you're saying and from what Mr. Butler said earlier, nothing ever gets struck because you're still taking it as a layperson and not necessarily an expert, if that's the determination you make.

MS. HELTON: Well, there may be some witnesses who do attempt to testify as an expert in areas for which it's clear they don't have any expertise. I mean, that's always a possibility. I'm not sure that I see that here today with Mr. Yupp, but -- so, you know, I think the holding the process out there and the ability to do that is not a bad thing for the Commission. But here I think maybe -- I'm trying to think of the right way to say this -- we might be in a little bit of overkill.

MR. BECK: Mr. Chairman, can I have a couple of seconds here?

CHAIRMAN GRAHAM: Sure.

MR. BECK: We use the evidence code. It's instructive for us on what to let in and what not, but it's not determinative. And what determines it is the section of 120.569 that Mary Anne read earlier, and it's whether a reasonably prudent person in the conduct of affairs would rely upon it. So that's the question for you is given Mr. Yupp's background, does he meet that test or not? You know, I would think he does, but, you know, that would be my recommendation.

CHAIRMAN GRAHAM: I agree with you. Mr. Moyle, I guess I don't agree with either one of your challenges.

MR. MOYLE: Okay. And like I said, I mean, we'll work our way through this, you know. I will recollect at one point -- it's a little bit of a war story, but there was a person who was proffered as a legal expert in Florida law on the Power Plant Siting Act, and it was -- voir dire was permitted and the person was not a member of the Florida Bar, I don't think had ever given advice on the Power Plant Siting Act. And when I asked him, "When did you first read it?" it was very recently. I mean --

CHAIRMAN GRAHAM: On the plane over.

MR. MOYLE: I'm sorry?

CHAIRMAN GRAHAM: On the plane over.

(Laughter.)

MR. MOYLE: It might have been a little longer. But -- and to be candid, I mean, I made the objection and it was overruled, so he was permitted to testify. But, you know, we'll continue to work -- on a lot of these dockets we've worked with the parties and staff on things. But I appreciate the discussion, the chance to ask some questions. And it does make a difference because, you know, based on your indication, he, I think, will be an expert. So when asking experts questions, I'm able to show them expert reports from other experts and say, well, look here's what NARUC says, you know. What do you think about that? If it was a fact witness, he would say, I don't know. I'm just here testifying about the production costs that were given to me by PetroQuest. But by your ruling that he's an expert, that's fair game for me to put a report in front of him and ask him some questions about it.

CHAIRMAN GRAHAM: That's true. Okay. Mr. Butler.

MR. BUTLER: I would move that Mr. Yupp's prefiled direct testimonies be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert his prefiled direct testimony into the record as though read.

MR. BUTLER: Thank you. Mr. Chairman, I would note that Mr. Yupp's exhibits GJY-1 --

CHAIRMAN GRAHAM: Hold on a second. Should we do his direct and rebuttal since we've voir dired both of them or should we just wait until later to do the rebuttal?

MR. BUTLER: We're not -- I'm sorry.

CHAIRMAN GRAHAM: We're not going to take them both up today, right now, but I just --

MS. BROWNLESS: If I may go back to the ruling on the objection, I think in order that the record is clear, you should rule that on the specific areas of expertise that FPL identified in their notice so that we clearly understand that Mr. Yupp is an expert in the fields listed on the notice. And if John can read those, then we have a clear ruling on the record.

MR. MOYLE: They're already made part of the record. They've been filed.

MS. BROWNLESS: Well, I mean, what I'm getting to is that I think the record needs to be clear the areas of expertise that were listed were natural gas financial hedging projections and calculations associated with gains and losses for asset optimization activities, projection and calculation of costs associated with asset optimization activities, projection of fuel costs and projection of physical hedging costs. Those were the areas tendered, and I assume Mr. Butler wants him qualified as an expert in all of those.

MR. BUTLER: I do, but I had understood Mr. Moyle only to be challenging two of them specifically, his expertise in natural gas financial hedging and production costs estimates -- or projections for physical hedges, and I understood the ruling to be that those were overruled, so --

MS. BROWNLESS: Good. Thank you.

MR. MOYLE: So I think that takes you to the place where he's an expert in everything you designated.

CHAIRMAN GRAHAM: Okay. So we've entered his direct testimony into the record as though read.

MS. BROWNLESS: Yes, sir.

MR. BUTLER: And I was just noting that his exhibits GJY-1 through GJY-5 have been premarked for identification as staff's Exhibits 2, 3, 4, 5, and 6.

CHAIRMAN GRAHAM: Duly noted.

MR. BUTLER: Thank you. And -- I'm sorry?

MR. MOYLE: No. I was going to jump in on other point. I mean, I know that you have a desire to try to move this along, and that's fine by FIPUG. We voir dired on both direct and rebuttal and we're pleased to do both at the same time if Mr. Butler wants to do that.

CHAIRMAN GRAHAM: Well, no, because he's going to be back -- we're not taking both together, so he's going to be back up here.

MR. MOYLE: If you want to do both together, no objection.

CHAIRMAN GRAHAM: Okay.

MR. BUTLER: I thought we had voir dired on both.

CHAIRMAN GRAHAM: We did.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 150001-EI

MARCH 3, 2015

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2014 results of FPL's activities under the Incentive Mechanism that was approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit GJY-1, consisting of four pages:

- Page 1 – Total Gains Schedule
- Page 2 – Wholesale Power Detail
- Page 3 – Asset Optimization Detail (Confidential)
- Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. It was created by the Stipulation and Settlement that was approved in FPL's 2012 rate case by Order No. PSC-13-0023-S-EI. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement (AMA). Under the Incentive Mechanism, customers receive 100% of the gains up to $46 million.

Incremental gains above $46 million are to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $46 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million. FPL is allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs, as well as variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case).

Q. Please summarize the activities and results of the Incentive Mechanism for 2014.

A. FPL's activities under the Incentive Mechanism in 2014 delivered nearly $67.63 million in total gains as described in my Exhibit GJY-1, page 1, Table 1, column 5. Of these total gains, and per the sharing parameters described above, FPL is allowed to retain $12.98 million (see Exhibit GJY-1, page 1, Table 2, column 9). FPL witness Keith describes how FPL's recovery of this amount will be handled in the Fuel Cost Recovery schedules. During 2014, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation and firm electric transmission. Additionally, FPL entered into an Asset Management Agreement related to a small portion of upstream gas transportation during 2014. The total gains of nearly $67.63 million exceeded the sharing threshold of $46 million. Therefore, the incremental gains above $46 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2014.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2014.

A. The details of FPL's 2014 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $43,475,917 on wholesale sales and savings of $10,528,280 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2014.

A. The details of FPL's 2014 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $13,622,670 of gains that were the result of eight different forms of asset optimization.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2014?

A. Yes. FPL incurred personnel expenses of $406,314 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $54,114 in expenses related to the first stages of implementation of OATI WebTrader software. The features of WebTrader will help facilitate streamlined power trade entry, transmission procurement, power scheduling, and accounting checkout. FPL expects that the WebTrader software will help FPL deliver additional value to customers by facilitating speed and flexibility in power trading. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $460,428 in 2014.

Additionally, FPL's actual wholesale power sales from its own generation resources in 2014 totaled 2,040,082 MWh, or 1,526,082 MWh above the 514,000 MWh threshold, resulting in variable power plant O&M expenses of $2,259,986 (reflects the volume above the threshold multiplied by $1.51/MWh; the average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs minus a true-up of $44,399 from 2013). Page 4 of Exhibit GJY-1 provides the details of FPL's Incremental Optimization Costs for

2014.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2014?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2014. On the wholesale power side, suitable market conditions, predominantly related to cold weather in January, helped drive FPL's wholesale power sales to the highest level since 2004 and the second highest level in the last 14 years. Gains on power sales reached the highest level since 1999. Asset optimization activities related to natural gas that had not taken place prior to the inception of the Incentive Mechanism generated slightly more than $11.96 million in gains, and optimization of FPL's firm transmission service on the Southern Company system added another $1.66 million in gains. In total, these activities delivered $67,626,867 of gains, which contrasts very favorably to the total optimization expenses (personnel and variable power plant O&M) of $2,720,415.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 150001-EI

APRIL 7, 2015

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in the predecessors to this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present data on FPL's hedging activities, by month, for calendar year 2014. This data is required per Item 5 of the Resolution of Issues in Docket 011605-EI that was approved by the Commission per Order No. PSC-02-1484-FOF-EI, which states:

"5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g. fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument."

Section III of the Hedging Order Clarification Guidelines that were approved by the Commission per Order No. PSC-08-0667-PAA-EI, issued on October 8, 2008, clarified that this data is to be provided each April for the prior calendar year.

Q. Are you sponsoring an exhibit for this proceeding?

A. Yes. I am sponsoring Exhibit GJY-2 – August through December 2014 Hedging Activity True-Up.

Q. Please describe FPL's hedging objectives.

A. Consistent with the guiding principles described in Section IV of the Hedging Order Clarification Guidelines, the primary objective of FPL's hedging program is to reduce the impact of fuel price volatility in the fuel adjustment charges paid by FPL's customers. FPL does not execute speculative hedging strategies aimed at "out guessing" the market. For 2014, FPL implemented a well-disciplined, well-defined and well-controlled hedging program in compliance with FPL's 2013 Risk Management Plan that was approved by the Commission in Order No. PSC-12-0664-FOF-EI, issued on December 21, 2012.

Q. Please summarize FPL's 2014 hedging activities.

A. Consistent with its approved 2013 Risk Management Plan, FPL hedged a portion of its natural gas fuel portfolio for 2014 utilizing fixed price transactions. A fixed price transaction allows a buyer to lock in the price of a commodity for a set volume over a set period of time. As described in the 2013 Risk Management Plan, FPL did not hedge heavy fuel oil for 2014, primarily due to the significant drop in heavy oil consumption projections.

Actual 2014 natural gas prices settled, on average, higher than the forward prices that were in effect when FPL was executing its natural gas hedges for 2014. As would be expected under the approved hedging approach, this increase in natural gas prices resulted in reported natural gas hedging savings for the year, as shown on Exhibit GJY-2.

Q. Does your Exhibit GJY-2 provide the detail on FPL's 2014 hedging activities required by Item 5 of the Resolution of Issues?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

SUPPLEMENTAL TESTIMONY OF GERARD J. YUPP

DOCKET NO. 150001-EI

SEPTEMBER 21, 2015

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company (FPL) as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. In addition, I address the gas reserves projects that are included in the 2016 Projection Filing, as well as O&M expenses associated with gas reserves projects that FPL has included for recovery in the 2016 fuel factors. I also review the interim results of FPL's 2015 hedging program and its 2016 Risk Management Plan. Additionally, my testimony addresses the Incremental Optimization Costs included in FPL's 2016 Projection Filing and the 2014 results of the Incentive Mechanism that was approved in Order No. PSC-13-0023-S-EI dated January 14, 2013. Lastly, I present the projected fuel savings resulting from the operation of the Port Everglades Next Generation Clean Energy Center (PEEC) from June through December 2016.

Q. Does your supplemental testimony incorporate into FPL's 2016 Projection Schedules the impact of acquiring the Cedar Bay facility and terminating the existing Cedar Bay power purchase agreement ("PPA") consistent with the terms of the settlement agreement between FPL and the Office of Public Counsel ("OPC") that was approved in Docket No. 150075-EI by the Commission at the agenda conference held on August 27, 2015?

A. Yes. I have incorporated the requirements of the Cedar Bay Settlement Agreement into FPL's 2016 Projection Schedules included with this filing.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-3: 2016 Risk Management Plan
- GJY-4: Hedging Activity Supplemental Report for 2015 (January through July)
- GJY-5: Appendix I
- Schedules E2 through E9 of Appendix II

FUEL PRICE FORECAST

Q. What forecast methodologies has FPL used for the 2016 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter (OTC) forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time and are consistent with the prices at which FPL can execute transactions for its hedging program. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the short-term is incorporated into the curves at all times. The methodology allows FPL to execute hedges consistent with its forecasting method and to optimize the dispatch of its units in changing market conditions. FPL utilized forward curve prices from the close of business on July 27, 2015 for its 2016 projection filing, which is the most current information that could be incorporated into FPL's schedule for calculating the 2016 FCR Clause factors.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2016 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of Liquefied Natural Gas (LNG) and Canadian natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

Natural gas prices are not projected to change substantially in 2016. Although working natural gas rigs are down approximately 87% since the peak in August 2008 and 36% year-on-year, efficiency improvements in the shale regions are leading to record levels of production. Natural gas production is expected to grow by an average rate of 5.4% in 2015 and 2.3% in 2016. EIA expects moderate production growth through 2016, with increases in the Lower 48 states expected to more than offset long-term production declines in the Gulf of Mexico. Increases in drilling efficiency will continue to support growing natural gas production despite relatively low natural gas prices. Increases in domestic natural gas production are expected to reduce imports from Canada and support growth in exports to Mexico. The EIA projects LNG exports will increase to an average of 0.79 billion cubic feet (BCF) per day in 2016.

Total natural gas consumption in 2016 is expected to average 76.5 BCF per day, roughly flat to the projected consumption level in 2015. Natural gas consumption in the power sector is projected to increase by 13.9% in 2015 and then decrease by 3.4% in 2016, while industrial sector consumption is expected to increase by 2.3%

in 2015 and by 5.0% in 2016, as industrial consumers continue to take advantage of low natural gas prices. Natural gas storage levels, a key benchmark for the supply/demand balance, were 3.03 trillion cubic feet (TCF) on August 14, 2015, or 0.49 TCF (19%) above the level at the same time a year ago and 0.08 TCF (2.7%) above the five-year average from 2010 through 2014. Natural gas storage is currently projected to reach approximately 3.87 TCF at the end of October 2015, or 69 BCF (1.8%) above the five-year average for that time.

Q. What are the factors that FPL expects to affect the availability of natural gas to FPL during the January through December 2016 period?

A. The key factors mainly relate to the balance of gas transportation and demand in Florida, specifically, (1) the capacity of the Florida Gas Transmission (FGT) pipeline into Florida; (2) the capacity of the Gulfstream Natural Gas System (Gulfstream) pipeline into Florida; (3) the portion of FGT and Gulfstream capacity that is contractually committed to FPL on a firm basis each month; and (4) the natural gas demand in the State of Florida.

The current capacity of FGT into the State of Florida is approximately 3,100,000 MMBtu/day and the current capacity of Gulfstream is approximately 1,260,000 MMBtu/day. FPL's total firm transportation capacity on FGT ranges from 1,150,000 to 1,374,000 MMBtu/day, depending on the month. FPL has firm transportation capacity on Gulfstream of 695,000 MMBtu/day.

Additionally, FPL has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 580,000 MMBtu/day of firm transport on the Southeast Supply Header (SESH) pipeline, 121,500 MMBtu/day (May through December) to 200,000 MMBtu/day (January through April) of firm transport on the Transcontinental Gas Pipe Line Company, LLC (Transco) Zone 4A lateral, and 200,000 MMBtu/day (January through March and November through December) to 345,000 MMBtu/day (April through October) of firm transport on the Gulf South Pipeline Company, LP (Gulf South) pipeline. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state; however FPL's firm transportation rights on these pipelines provide access for up to 1,046,500 MMBtu/day during the summer season of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply. FPL projects that during the January through December 2016 period, 50,000 MMBtu/day to 150,000 MMBtu/day of non-firm natural gas transportation capacity will be available into the state, depending on the month. FPL projects that it could acquire some of this capacity, if economic, to supplement FPL's firm allocation on FGT and Gulfstream.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 BCF of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama. While the acquisition of upstream transportation capacity (i.e., SESH) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. Approximately 18% of FPL's supply continues to be sourced from off-shore sources. Additionally, as FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. Storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2016 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2016 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to its quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

The recent decline in crude oil prices reflects concerns about lower economic growth in emerging markets, expectations of higher oil exports from Iran, and continuing actual and expected growth in global inventories. Average heavy oil prices are forecasted to be higher in 2016 compared to the expected average prices in 2015. In its August 2015 Short-Term Energy Outlook report, the U.S. Energy Information Administration (EIA) forecasts crude oil prices will average approximately $4 per barrel higher in 2016 compared to 2015. The EIA anticipates global crude oil and liquid fuels production to grow by 2.3 million barrels per day (b/d) in 2015 and 0.3 million b/d in 2016. Total U.S. crude oil and liquid fuels production growth is projected to slow down from an increase of 0.9 million b/d in 2015 to a decline of 0.1 million b/d in 2016. While the projected global production growth remains roughly flat in 2016, world demand is still projected to grow by 1.47 million b/d in 2016. As always, an increase in geopolitical concerns could create additional upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2016 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2016 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for St. Johns' River Power Park (SJRPP) and Plant Scherer?

A. FPL's projected dispatch costs for both plants are based on FPL's price projection for spot coal delivered to the plants.

Q. What is the basis for FPL's projections of the dispatch cost of coal for Cedar Bay?

A. FPL's projected dispatch costs for Cedar Bay are based on the current cost of inventory at the site.

Q. Please provide FPL's projection for the dispatch cost of coal at SJRPP, Plant Scherer, and Cedar Bay for the January through December 2016 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by plant and by month, is shown on page 3 of Appendix I.

Q. Do the fuel costs reflected on Schedule E3 for heavy oil, light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. Except in the case of Cedar Bay, the dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for heavy oil, light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type. For Cedar Bay, FPL dispatched the unit at the current inventory cost based on the assumption that it would most likely not replace the coal that is consumed due to the anticipated retirement of the facility at the end of 2016.

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the GenTrader model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to GenTrader for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2016?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units.

The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2016.

Q. Please describe the significant planned outages for the January through December 2016 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. Turkey Point Unit 4 is scheduled to be out of service from March 28, 2016 until April 30, 2016, or 33 days, during the period. St. Lucie Unit 1 is scheduled to be out of service from September 26, 2016 until October 27, 2016, or 31 days, during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2016 period.

A. FPL projects to put the PEEC into commercial operation on June 1, 2016. This unit will add approximately 1,240 MW of capacity to FPL's system.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2016?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction. Additionally, FPL is a member of the Florida Cost-Based Broker System (FCBBS). The FCBBS matches hourly cost-based bids and offers to maximize savings for all participants. For 2016, the FCBBS will be comprised of 9 members, including FPL. FPL can also purchase and sell power during emergency conditions under several types of Emergency Interchange agreements that are in place with other utilities within Florida.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, fuel availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 1,506,600 MWh of wholesale (off-system) power sales for the period of January through December 2016. The projected fuel cost related to these sales is $47,836,482. The projected transaction revenue from these sales is $65,714,282. After taking into account the transmission costs for those sales, the projected gain is $13,419,650.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2016 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 950,880 MWh at a cost of $33,524,545. If FPL generated this energy, FPL estimates that it would cost $46,493,801. Therefore, these purchases are projected to result in savings of $12,969,256.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of Palm Beach County (SWA). FPL also has contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA). Additionally, FPL purchases energy from JEA's portion of the SJRPP Units. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2016 period.

A. Energy purchases under the SWA agreements are projected to be 913,536 MWh for the period at an energy cost of $22,783,691. Energy purchases from the JEA-owned portion of SJRPP are projected to be 1,769,451 MWh for the period at an energy cost of $66,383,506. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 540,890 MWh at a cost of $3,737,770. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 1,093,725 MWh at a cost of $53,702,765.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the GenTrader model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 578,769 MWh of energy at a cost of $4,109,711. These projections are shown on Schedule E6 of Appendix II.

GAS RESERVES PROJECTS

Q. What are the projected costs that FPL has included in its 2016 Projection Schedules for the Woodford Gas Reserves Project that was approved in Order No. PSC-15-0038-FOF-EI, dated January 12, 2015?

A. FPL has included approximately $57.6 million in projected costs, including natural gas transportation from the outlet of the gathering system to Perryville (SESH), related to the Woodford Gas Reserves Project.

Q. Has FPL entered into any additional gas reserves projects subsequent to the approval of the FPL Gas Reserves Guidelines in Order No. PSC-15-0284-FOF-EI that was issued on July 14, 2015?

A. No. However, FPL is actively exploring additional opportunities for gas reserves projects that will help provide customers with physical gas supply at stable pricing over the production term.

Q. Has FPL included incremental O&M expenses related to the accounting, technical services or business management functions of gas reserves projects in its 2016 FCR Clause factors?

A. Yes. FPL has included projected incremental O&M expenses associated with gas reserves projects of $500,000 in its projections for 2016.

Q. Please describe the types and amounts of costs that are included in FPL's projections of incremental O&M expenses related to gas reserves projects.

A. FPL projects to incur incremental expenses of approximately $120,000 related to external accounting and audit services, approximately $100,000 for technical services related to reservoir engineering and production operations, and approximately $280,000 for additional personnel who will perform functions in the land management and business management areas.

HEDGING/ RISK MANAGEMENT PLAN

Q. Please describe FPL's hedging objectives.

A. The primary objective of FPL's hedging program has been, and remains, the reduction of fuel price volatility. Reducing fuel price volatility helps deliver greater price certainty to FPL's customers.

This objective was clearly defined in Item 1 of the Proposed Resolution of Issues that was approved in Order No. PSC-02-1484-FOF-EI, dated October 30, 2002, which states, "Each investor-owned utility recognizes the importance of managing price volatility in the fuel and purchased power it purchases to provide electric service to its customers. Further, each investor-owned electric utility recognizes that the greater proportion of a particular fuel or purchased power it relies upon to provide electric service to its customers, the greater the importance of managing price volatility associated with that energy source."

Q. Does FPL rely on a greater proportion of a particular fuel to provide electric service to its customers?

A. Yes. FPL is projecting that nearly 72% of the electricity it produces in 2016 will be generated with natural gas.

Q. Does FPL engage in speculative hedging strategies aimed at "out guessing" the market?

A. Absolutely not. FPL's hedging program is consistent with the guiding principles contained in Section IV of the Hedging Order Clarification Guidelines that the Commission approved in Order No. PSC-08-0667-PAA-EI, dated October 8, 2008. Section IV, part b, states that, "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." This point is further substantiated in Section IV, part d, which states, “The Commission does not expect an IOU to predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.”

Q. Is the purpose of hedging to reduce fuel costs over time?

A. No. In fact, in the same Hedging Order Clarification Guidelines (Section IV, part d), the Commission acknowledged that, “hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers, if fuel prices actually settle at lower levels than at the time that hedges were placed.” The Commission went on to state that it “recognizes this as a reasonable trade-off for reducing customers’ exposure to fuel cost increases that would result if fuel prices actually settle at higher levels than when the hedges were placed.” These statements clearly underscore the fact that hedging is not designed to reduce fuel costs. Rather, hedging is a tool that is utilized to control volatility, specifically the volatility of fuel adjustment charges.

Q. Does FPL’s hedging program balance the goal of reducing customers’ exposure to fuel cost increases against the goal of allowing customers to benefit from falling prices?

A. Yes. This goal is achieved by limiting hedging to only a portion of the total expected fuel consumption. This balance can be seen in FPL’s mid-course correction that was filed on March 9, 2015. As natural gas prices declined substantially from the original 2015 projections, FPL was able to decrease fuel charges by approximately $218 million from May 1, 2015 through the end of the year.

Q. Has FPL filed a comprehensive risk management plan for 2016, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its 2016 Risk Management Plan as part of its annual Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up filing on August 4, 2015. The 2016 Risk Management Plan was included as Exhibit GJY-3.

Q. Please provide an overview of FPL's 2016 Risk Management Plan.

A. FPL's 2016 Risk Management Plan remains consistent with FPL's overall objectives that I previously described. It addresses Items 1-9 and 13-15 of Exhibit TFB-4, which is required per the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOF-EI dated October 30, 2002. FPL's 2016 Risk Management Plan specifically addresses the parameters within which FPL intends to place hedges during 2016 for its projected natural gas requirements in 2017. FPL plans to hedge the percentages of its 2017 projected natural gas requirements over the time periods in 2016 that are described in the plan. As described in the plan, FPL discontinued heavy fuel oil hedging in 2013 and does not intend to execute hedges for its 2017 heavy fuel oil requirements.

Q. Are there any modifications to FPL's 2016 Risk Management Plan from prior years?

A. Yes. FPL's 2016 Risk Management Plan has been modified to include the Woodford Gas Reserves Project I referenced earlier in my testimony. Gas supply from the Woodford Gas Reserves Project serves as a long-term physical hedge and the projected production volumes have been incorporated as such in the percentage of natural gas that FPL hedges for the 2017 period. Furthermore, with the approval of the FPL Gas Reserves Guidelines, also referenced previously in my testimony, FPL's 2016 Risk Management Plan addresses how subsequent gas reserves projects will be incorporated into the hedging program. Additionally, FPL's 2016 Risk Management Plan details several process and reporting requirements that are included in the Gas Reserves Guidelines.

Q. Has FPL filed a Hedging Activity Supplemental Report for 2015, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. FPL filed its Hedging Activity Supplemental Report for 2015 (January through July) on August 14, 2015. The Hedging Activity Supplemental Report is identified as Exhibit GJY-4.

Q. Have FPL's 2015 hedging strategies been successful in achieving FPL's hedging objectives?

A. Yes. FPL's hedging strategies have been successful in reducing fuel price volatility and delivering greater price certainty to its customers, while also allowing FPL's customers to benefit from falling fuel prices.

<u>THE INCENTIVE MECHANISM</u>

Q. Is FPL seeking to recover through the FCR Clause projected incremental operating and maintenance expenses (Incremental Optimization Costs) during the January through December 2016 period with respect to implementing its program for expanded short-term wholesale purchases and sales, as well as asset optimization measures (the Incentive Mechanism) that was approved in Order No. PSC-13-0023-S-EI, dated January 14, 2013?

A. Yes. FPL has included projected Incremental Optimization Costs associated with the Incentive Mechanism in its projections for 2016.

Q. What types of Incremental Optimization Costs is FPL entitled to include for recovery through the fuel clause?

A. Per Order No. PSC-13-0023-S-EI, FPL is entitled to recover reasonable and prudent Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and (ii) variable power plant O&M costs incurred to generate additional output in order to make wholesale sales in excess of 514,000 MWh.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software and hardware expenses.

A. FPL projects to incur incremental expenses of $409,812 in 2016 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism. FPL is also projecting to incur $56,800 in expenses for the licensing and maintenance of OATI WebTrader software. As I described in my testimony last year, the OATI WebTrader software is a tool used for power trading. The features of WebTrader facilitate streamlined trade entry, transmission procurement, power scheduling, and accounting checkout. FPL expects that the WebTrader software will help FPL deliver additional value to customers by facilitating speed and flexibility in the power trading area.

Q. Please describe the costs that are included in FPL's projections for variable power plant O&M expenses.

A. FPL projects to incur incremental expenses related to variable power plant O&M of $1,498,826 in 2016. FPL projects to sell 1,506,600 MWh of economy power (Schedule E6) in 2016 which is 992,600 MWh above the 514,000 MWh of such sales that were projected in FPL's 2013 Test Year and used as a threshold for power sales in the Incentive Mechanism. Based on data provided as part of the 2013 Test Year projections, FPL has determined that its incremental variable power plant O&M cost is $1.51/MWh. Applying this rate to projected excess sales of 992,600 MWh above the threshold yields total variable power plant O&M of $1,498,826 in 2016.

Q. Has FPL included in its 2015 actual-estimated FCR true-up and 2016 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3 and Capacity Clause-Transmission of Electricity by Others) for both 2015 and 2016.

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2014?

A. FPL's asset optimization activities in 2014 delivered total benefits of $67,626,867. The total gains exceeded the sharing threshold of $46 million and, therefore, the gains above $46 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $54,190,319 (net after incremental personnel, software, and hardware expenses are removed). FPL will receive $12,976,120 which is included for recovery in FPL's 2016 FCR Clause factors.

Q Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2014?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the new Incentive Mechanism. For the purpose of this comparison, I have included the same savings of $58 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $50.3 million, while FPL would have retained $7.7 million because the three-year rolling average threshold for wholesale sales would have been exceeded. In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated nearly $12 million of additional savings in 2014. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received $54.2 million of savings under the Incentive Mechanism. This is $3.9 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

CALCULATION OF FUEL SAVINGS ASSOCIATED WITH THE OPERATION OF PEEC

Q. Will the operation of PEEC during 2016 result in fuel savings for FPL's customers?

A. Yes. This unit's high efficiency creates substantial fuel savings for FPL's customers. For the June through December 2016 period, the operation of PEEC is projected to result in fuel savings for FPL's customers of $43,089,540.

Q. How did FPL calculate the projected fuel savings associated with the operation of PEEC?

A. FPL utilized its GenTrader model to quantify the fuel savings associated with the operation of PEEC. This model is used to calculate the fuel costs that are included in FPL's projection filing. The same forecasted fuel prices and other assumptions that are reflected in the projection filing were used for analyzing the PEEC fuel savings. In order to calculate the PEEC fuel savings, FPL ran two separate production cost simulations, one without PEEC and one with PEEC. A comparison of the total system fuel costs from GenTrader for the two simulations showed that the fuel costs were $43,089,540 lower in the case that included PEEC than in the case without PEEC.

Q. Does this conclude your testimony?

A. Yes it does.

BY MR. BUTLER:

Q Okay. So with that, I would ask Mr. Yupp to provide his oral summary of his prefiled direct testimonies.

A Good afternoon, Commissioners, Chairman Graham and Commissioners. My testimony addresses FPL's projections for the dispatched costs and availabilities of fossil fuels, generating unit heat rates and availabilities, and the quantities and costs of wholesale power transactions. Additionally, my testimony addresses FPL's hedging program, including its 2016 risk management plan, the results of the incentive mechanism program in 2014, including the projected incremental O&M costs for 2016, the projected costs of the Woodford Gas Reserves Project that are included in FPL's 2016 projection schedules, and, lastly, the savings associated with the commercial operation of the Port Everglades Energy Center beginning in June of 2016.

In 2016, FPL is projecting that nearly 72 percent of the electricity it produces will be generated with natural gas. Clearly managing the price volatility associated with natural gas is of great importance. The objective of FPL's hedging program is to reduce fuel price volatility, not to reduce fuel costs over time.

FPL does not engage in speculative hedging strategies aimed at outguessing the market as FPL cannot predict future fuel prices. Instead, FPL executes a well-disciplined independently controlled hedging program that reduces fuel price volatility and delivers greater price certainty to FPL's customers.

In 2014, FPL's asset optimization activities under the incentive mechanism delivered approximately $67.2 million in total net benefits. The gains over the $46 million threshold will be shared between FPL and its customers, resulting in total net benefits to customers off $54.2 million and total benefits to FPL of $13 million.

A comparison to the previous wholesale sales sharing mechanism shows that under the new mechanism customers receive nearly $4 million more in benefits than they would have if the old mechanism were still in place. This demonstrates the new incentive mechanism is clearly delivering added value for customers as FPL and the Commission envisioned when it was approved.

And, finally, FPL projects that the commercial operation of the highly efficient Port Everglades Energy Center beginning in June of 2016 will result in almost $40 million in fuel savings for FPL customers for the June through December 2016 period. And that concludes my summary. Thank you.

MR. BUTLER: Thank you, Mr. Yupp. I tender Mr. Yupp for cross-examination.

CHAIRMAN GRAHAM: Okay. OPC.

MR. SAYLER: Good afternoon, Mr. Chairman. I have a process question before I get started.

CHAIRMAN GRAHAM: Sure.

MR. SAYLER: Earlier today I distributed four exhibits that are stipulated interrogatory responses by FPL, Gulf, TECO and Duke. I can either do all, ask you to identify and mark all of them now, or do it at each time the witness goes on the stand, whichever you --

CHAIRMAN GRAHAM: Let's mark them all now.

MR. SAYLER: All right.

CHAIRMAN GRAHAM: Staff, I don't know what exhibit number we're at right now. Is it 47 or 48?

MR. SAYLER: I believe it's 115.

CHAIRMAN GRAHAM: 115. I'm sorry.

MS. BROWNLESS: Hold on a sec. Haven't these already been stipulated into the record or no?

MR. SAYLER: I mean, they agreed to stipulate them into the record, but for purposes of briefing, it is helpful to have an exhibit number to reference when --

MS. BROWNLESS: Well, there is an exhibit number. I guess that's why I'm confused. The fourth set of interrogatories are already marked.

MR. SAYLER: What number?

MS. BROWNLESS: I've got it. I'm sorry. I'm confused. Go ahead. I'm sorry. They're not on this list. Excuse me.

CHAIRMAN GRAHAM: Okay. What number did we leave off on?

MS. BROWNLESS: It's 115.

CHAIRMAN GRAHAM: So this would be 115 or do we need to go to 116?

MS. HELTON: 115 would be the first one to be marked for OPC.

CHAIRMAN GRAHAM: Okay. Mr. Sayler, which is the first one?

MR. SAYLER: I would say the FPL responses to OPC interrogatories.

CHAIRMAN GRAHAM: So that will be 115.

MR. SAYLER: And it says stipulated exhibit on it.

(Exhibit 115 for marked identification.)

The next one would be DEF responses to OPC interrogatories stipulated exhibit as 116.

CHAIRMAN GRAHAM: All right.

(Exhibit 116 marked for identification.)

MR. SAYLER: The next one, and we're going in order of the witnesses, would be Gulf responses to OPC interrogatories stipulated exhibit.

CHAIRMAN GRAHAM: That's 117.

(Exhibit 117 marked for identification.)

MR. SAYLER: And followed up, rounded out by TECO responses to OPC interrogatories stipulated exhibit, 118.

CHAIRMAN GRAHAM: 118.

(Exhibit 118 marked for identification.)

Do we have a copy of all four of these up where the witnesses are?

MR. SAYLER: No, sir, but I will put one there right now.

CHAIRMAN GRAHAM: Okay.

MR. SAYLER: Again, I would like to thank the utilities and the parties for stipulating to these interrogatory responses into the record to greatly decrease cross from Public Counsel's Office.

CHAIRMAN GRAHAM: Okay. The witness is yours.

MR. SAYLER: Thank you, Mr. Chairman. I didn't want cause the mike to squeak when I moved it.

EXAMINATION

BY MR. SAYLER:

Q Good afternoon, Mr. Yupp. How are you today?

A Good afternoon. I'm fine. Thank you.

Q Are you familiar with the statement, and I quote, hedging programs are designed to assist in managing the impacts of fuel price volatility, and within any given calendar period hedging can result in gains and losses and over time gains and losses are expected to offset one another?

A Yes.

Q Okay. And, Mr. Yupp, from 2002 to 2014 your company incurred approximately $3.5 billion in hedging costs or losses?

A No, that's not correct.

Q What is the correct number?

A I believe the correct number is 3.162 per the corrected response.

Q All right. And that is inclusive of oil and natural gas?

A That's correct.

Q But if you were to break out just the natural gas hedging losses, it would be closer to that $3.5 billion number; isn't that correct?

A I will have to look for that. Yes, that's correct.

Q Okay. Thank you.

And for 2015, as it relates to natural gas hedging costs or losses, your company is projecting to incur about 382 million; is that correct?

A That number was given in an interrogatory response that has been updated since then.

Q Okay. What is the updated number?

A The updated number that I saw on Friday was approximately 490 million.

Q 490 or 419?

A 490.

Q Okay. And is that due to the continued slide in the price of natural gas?

A That is correct.

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

A That is correct.

Q Okay. And you would also agree that natural gas market conditions in 2015 are different from what they were in 2002 when hedging commenced; is that correct?

A I believe that the supply situation at the current point in time is different with ample supply of shale gas, yes.

Q Okay. And you would -- and that leads to my next question. You would agree that advances in recovering gas from shale formations has increased the supply since 2002?

A That is correct.

Q All right. You would agree that the addition of shale gas into the market has also decreased the price of gas.

A Yes. By default, supply and demand, when there is adequate supply or in the case that we're in right now potentially oversupply, prices will decrease. It's a supply and demand issue, yes.

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

A Yes, it is.

Q Do you know what the price of natural gas is today -- or most recent when you checked it?

A I believe on Friday morning the cash market was trading in the upper 1.90s. I believe the NYMEX for 2016 is roughly $2.50, somewhere in that range. I haven't seen the NYMEX market today, though.

Q All right. And you would agree that the trend of fuel price volatility is decreasing at this time.

A No, I would not.

Q Okay. And you would agree that your company does not estimate or forecast the fuel price volatility of the price of natural gas?

A That's correct, we do not. We do, however, as we stated in our interrogatories, we do use calculated volatilities based on a 12-month rolling average to put bands around our fuel forecasts so when we're doing economic evaluations, we generate a high and low band forecast using historical volatilities.

Q Okay. But you don't forecast volatility going forward; is that correct?

A We do not, no.

Q Okay. And a moment ago I asked you the question about fuel price volatility being decreasing.

A Right.

Q I know in rebuttal you have this exhibits and things of that nature, so I will ask you further questions at that time.

A Okay.

Q You would also agree that eliminating all fuel price volatility is not realistic; is that correct?

A Eliminating all fuel price volatility?

Q Yes. I mean, can you eliminate fuel price volatility in the market?

A Let me make sure I'm clear. Not through hedging, you're just saying it is -- can fuel price volatility be zero in the market?

Q Correct.

A Not that we have seen.

Q Okay. And unless natural gas fuel price volatility could be guaranteed to be zero, you think hedging should continue; is that correct?

A That is correct.

Q When it comes to hedging, does the company make any profit or return on natural gas financial hedging transactions entered into between the company and its hedging counterparties?

A No, we do not.

Q Okay. Does the company have any affiliate relationships with its hedging financial counterparties?

A No, we do not.

Q Okay. And does the company have in place corporate policies and procedures for its employees, including officers, which help prevent conflicts of interest as it relates to financial hedging transactions?

A Yes, we do.

MR. SAYLER: All right. Thank you very much, Mr. Yupp. I look forward to it on rebuttal.

THE WITNESS: Okay.

CHAIRMAN GRAHAM: Retail Federation?

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

CHAIRMAN GRAHAM: Mr. Brew.

MR. BREW: While I would love to cross-examine FPL's witness, I'll pass this time.

(Laughter.)

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: I do have some questions. I also have an exhibit I'd like to use with this witness.

CHAIRMAN GRAHAM: Sure.

MR. SAYLER: Mr. Chairman, while they're passing out that exhibit, were Exhibits 115 through 118 officially moved into the record, or do we do that at the end of --

CHAIRMAN GRAHAM: We do it at the end.

MR. SAYLER: Okay.

CHAIRMAN GRAHAM: Mr. Moyle, we'll give your exhibit number 119.

MR. MOYLE: Okay. Thank you, Mr. Chairman.

(Exhibit 119 for marked identification.)

CHAIRMAN GRAHAM: Did you purposely make this small?

(Laughter.)

MR. MOYLE: You've got to get the handy readers.

EXAMINATION

BY MR. MOYLE:

Q So, anyway, I do have some questions for you, Mr. Yupp, about Exhibit 119.

But let me just start by asking you a couple of general questions. You said on Friday you looked and the cash market price for natural gas was below $2 per million Btus; is that right?

A That is correct.

Q And can market prices -- is it your experience as an expert in hedging, can market prices be below production cost prices?

A I would say that market prices could not be below production costs for any extended period of time. I would think that maybe some of the stronger financial producers could withstand that, but I wouldn't think that would happen for an extended period of time, no.

Q And you also, I think, just said that NYMEX is showing not production costs but market costs for the year 2016 at 2.50 per million Btu; is that right?

A That is correct.

Q And so given your previous response, you would assume that 2.50 is above production cost levels; correct? That's an extended period of time. That's for the whole year.

A No, I wouldn't assume that at all. I think production costs obviously vary amongst producers, but that's what's built into the market right now. Will it last that -- will it stay that way? We don't know, so --

Q Right. And I'm just trying to understand with respect to your testimony that I don't think that they sell below their production costs maybe except for short periods of time, what you consider a short period of time to be.

A I don't know. I think that would vary with each producer on how long they could handle doing that. So I don't have an exact time frame on how long that might be.

Q Do you have any information about how production costs relate to a 2.50 annual projected cost for natural gas for 2016?

A I can see what our effective production -- well, I shouldn't say that -- what our effective delivered cost is to another pipeline coming out of our gas reserves transaction, yes.

Q How can you see that?

A It's filed in our projection filing for 2016.

Q What are your Woodford projected production costs for 2016?

A I don't know the specific production cost. I did not calculate that. The delivered cost to the Perryville Hub at the, I'll say inlet of the Southeast Supply Header pipeline was roughly in $2.70 range, so there's transport included in that.

Q And how much trans -- what do you call it, transporting?

A Yes. That number would be confidential.

Q Do you want to write it on a piece of paper for me?

A No.

Q I'll keep it confidential.

I assume it's a positive number; correct?

A Yes.

Q How much are you asking that the Commission allow you to recover for Woodford?

A The total number is $57.6 million in 2016.

Q What about 2015?

A 2015, there's a combination of actuals and estimates right now. I don't recall what the total number was in our estimated/actual filing. I can tell you just looking at the actuals with the estimates now, which would be a couple more months of actuals from when we made the filing, it would be roughly in the, I want to say, including transportation, probably $31 million range.

Q Any 2014 costs?

A Not that I'm aware of, no.

Q So the sum of those two numbers would be what you're asking to be recovered for Woodford in 2015 and '16, 31 million and 57.6?

A Roughly, yes.

Q Okay. And did ratepayers save money as a result of Woodford in 2015 based on your actuals and projected?

A In 2015 to date, no, there -- in calculating hedging gains or opportunity costs, the Woodford project was more expensive than the market. That's based on a market that fell over $1.50 from the time that we began the project.

The other thing that I think I need to clarify, because our results are out there on a monthly basis and we have actually just updated with staff actuals, the startup year of the Woodford project, I'll describe prices as fairly choppy because of the timing differences in the dollars that were being spent with production. So with those differences, we see effective costs that are really all over the place, from 6.50 to 12.50 and back down to three dollars and change.

So while the numbers are what they are in 2015, it is a startup phase. What we're looking at by the end of the year for a total effective delivered cost to Perryville, we should be very close to the range that we first projected. What we're seeing then on a very positive front is that drilling and completion costs are coming in lower than what were projected when we came here for approval, so costs are down.

We're also seeing that the -- there's been a re-estimation now of volumes, and we believe that we are going to get more volume than what we originally projected from the Woodford area. So, again, on a positive note, costs are down, volumes are up. And so the Woodford project, while, you know, we talk about comparing it to the market, the market has fallen over $1.50. Woodford, from a hedging -- is more than just from a hedging perspective. Certainly it can provide that physical hedge, but it is a long-term stable cost of volume of natural gas. It's a low price stable cost, so it's very beneficial to customers in our opinion.

Q What's the low price stable cost?

A I think next year, looking at costs that are in that $2.70 range, that is low price stable cost. So when you look at that price out over a given number of years, the bottom line is that the price of Woodford is disconnected from market prices. And so I would term in the -- you know, for next year $2.70 or in that range as low cost and stable.

Q Okay. So then based on the numbers you've shared with me today, it's only a 20-cent megawatt -- or 20-cent-per-million Btu loss if you go with the NYMEX 2.50 projected 2016 compared to the 2.70 production cost; is that right?

A As of today.

Q Okay.

A That would assume that NYMEX was going to settle at that cost.

Q All right. And the 2.70, is that the production cost, just to be clear?

A That is a delivered cost.

Q So what's the difference between the delivered cost and the production cost?

A I would term the production cost as what's coming out of the well. The delivered cost that we use on our exhibits that we update, that we actually updated for OPC and for staff include an effective delivered cost, which is the cost of gas including transportation delivered to the Perryville Hub or to the SESH pipeline.

Q And what's that number?

A That is the number I'm quoting to you.

Q 2.70?

A Yeah.

Q Okay. So the question -- and I appreciate -- you know, the Chair has always said, you know, if you want the witness to stop, tell him to stop. And you gave a very lengthy answer and that was okay.

A Uh-huh.

Q But the question I think I asked you was for 2015 what was the bottom line with respect to Woodford vis-a-vis ratepayer savings if there were any savings at all? It sounds like there were not savings; am I correct?

A No, there were not.

Q Okay. So what was the loss?

A The updated number actuals through September, I believe, is $5.5 million.

Q Okay. And then the same question with respect to 2016. What's the projected savings or loss as it relates to Woodford for 2016?

A I haven't looked. I haven't looked at that number.

Q How -- could you calculate that number if we used the 2.70 that you've been talking about and compare it to the NYMEX 2.50, that would -- you just figure out the production number?

A Yes, that's correct. You could.

Q So that would indicate that it's projected that there would also be a loss for customers related to Woodford in 2016; correct?

A At this point in time, correct.

Q Did you provide testimony in the Woodford case?

A I did not.

Q Did you follow the case?

A To the extent I could outside of what my responsibilities are.

Q And you had talked about the 3.48. I was using 3.50.

A Uh-huh.

Q It was my impression that there was a suggestion that the production costs were going to stay relatively flat over time, that that was what people were anticipating, but you're telling me, no, I think it actually is probably 80 cents that can get cut off the production cost; is that right?

A They have come in lower, yes. The updated exhibit, SF-8, as I'll refer to it, that we just had provided to staff in an interrogatory response shows it -- it is roughly in that ball park. Over the life of the project it should be 75 to 80 cents, I believe, lower.

Q Well, I guess you would view that as good news in that the ratepayers are projected to lose less money now as compared to they would if it was at 3.50, right, if production costs were at 3.50?

A Can you repeat that, please?

Q Sure. The updated projections suggest that ratepayers will lose less money at $2.70 production cost as compared to $3.50 production cost; right?

MR. BUTLER: Are you referring to 2016 particularly, Jon?

MR. MOYLE: Yes.

THE WITNESS: Yeah. I can't say whether customers are going to lose money or not in 2016. It hasn't happened yet.

BY MR. MOYLE:

Q Right.

A But certainly to your point, just mathematically, yes, if production costs are less and the market is less than the cost of production, then the better -- the lower the production cost, the better it is, yes.

Q Okay. Have you tallied, you know, since 2002, and I'm just going to use losses and gains, are you okay if I use the phrase "losses and gains" to talk about the results of hedging?

A I prefer opportunity costs, but if you'd like to use losses, that's fine.

Q Okay. Thank you for that. So what is the total loss or gain since 2002 to the best information that you have today as a result of hedging?

A For FPL's hedging program for all those years?

Q For hedging program for those years for natural gas.

A $3.1 billion or 3.2 rounded up loss.

MR. BUTLER: And, Jon, you were asking specifically for natural gas over the program as a whole?

MR. MOYLE: I asked for natural gas.

THE WITNESS: Oh, you wanted specifically natural gas. 3.5.

BY MR. MOYLE:

Q Okay. And I think you said 2015, you just gave an updated number to OPC of a loss of 490 million; is that right?

A Correct. Now that is based on months through September of actuals, October will soon become realized or confirmed, and two months of -- at the time two months of estimates, yes.

Q Do you expect the October numbers to drive the 490 number up?

A No, I do not.

Q Do you expect it to drive it down?

A No. October -- I should clarify. The number that I looked at, October is already realized. It will just get confirmed. So it comes in on a reporting basis as realized, but that number will not change. And then November just came off of the -- or NYMEX settled. I'm trying to remember the report I looked at. I don't believe NYMEX had settled yet, so I believe November and December would have been estimates.

Q Okay. So just so I'm clear, the 490 number does include what happened in October; right?

A Yes. That would be our -- I guess to clarify, that would be our best estimate of where 2015 will end.

Q Okay. And then the 3.5 billion loss since hedging has been done --

A On natural gas.

Q -- on natural gas --

A Right.

Q -- did that include the 490 number, the updated 490?

A No, it does not.

Q Okay. So what would you have to do, what would that do to the 3.5 billion?

A We would add 490 to it.

Q Okay. So that would make it 3.55 billion roughly?

A 490 million, it would make it 3.9 billion or 3.99.

Q Can we just call it 4 billion?

A We can.

Q Is that -- agree?

CHAIRMAN GRAHAM: Yes.

THE WITNESS: Yes, I think that's what it would be.

BY MR. MOYLE:

Q Thank you. Sometimes the millions and billions get a little confusing for me, so thanks for the clarity.

All right. So let's take a look at that Exhibit, if we could. So this is an exhibit, I'll represent to you, E&Y is Ernst & Young. It's entitled "The Pros and Cons of Hedging." And I'm assuming, given our prior conversation, that you're okay if I ask you some questions about the pros and cons of hedging?

A Yes.

(Transcript continues in sequence with Volume 3.)

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 3rd of November, 2015.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734