BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140001-EI

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

FILED DEC 03, 2014
DOCUMENT NO. 06552-14
FPSC - COMMISSION CLERK

VOLUME 4

Pages 467 through 535

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Monday, December 1, 2014

TIME: Commenced at 8:00 p.m.
Concluded at 9:00 p.m.

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

REPORTED BY: LISA GAINEY, CM, RPR
Court Reporter and
Notary Public in and for the
State of Florida at Large

APPEARANCES: (As heretofore noted.)

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I N D E X

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E X H I B I T S

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P R O C E E D I N G S

Whereupon,

KIM OUSDAHL

was called as a witness, having been previously duly sworn, was examined and testified as follows:

CONTINUED CROSS EXAMINATION

BY MR. MOYLE:

Q So, just to take that, the only way that you believe that FPL doesn't earn the return on their investment is if this Commission says you were imprudent?

A That's right. It's a required cost. We would have earned that cost if we acted imprudently.

Q And we talked about this in your deposition a little bit but stated conversely, every expense that's realized as a result of FPL's investment in this Woodford Project or other projects gets passed through to ratepayers, correct?

A That's correct. Expenses are incurred on behalf of customers. They are the beneficiaries of the production.

Q So, would you also agree that there's not much risk associated to -- there's not much risk associated with this deal for FPL shareholders and that the only risk we've identified is this Commission might

deem a decision imprudent or this Commission might lower the return on equity and there's no operational risk.

A Well, I think there's execution risk on any of the activities we engage in as a regulated entity. The Commission reviews our plans against our performance. And if we don't execute properly, there's a risk that we will have a disallowance.

Q What execution risk do you have in this proposed Woodford Project?

MR. BUTLER: I'm going to object to this line of questions because I don't see it relating to Ms. Ousdahl's testimony.

CHAIRMAN GRAHAM: I guess the question I have -- and I guess I'm taking the words right out of his mouth -- is who would be the best person to ask this question?

MR. BUTLER: He already asked to Mr. Forrest. I think that Dr. Taylor has quite of bit of knowledge about the nuts and bolts of the gas industry. Maybe that's something where he can get additional information, but as Mr. Moyle already acknowledged, he went through this whole line of questions.

So, if Mr. Forrest, who is really the right witness --

MR. MOYLE: Well, I want to understand the execution risk that FPL Is going to be incurring with respect to what it's doing in this deal and how much risk is it taking.

I mean, my understanding is Woodford is the operator. They got all the operation risk, and FPL is gathering paper and pushing paper through.

CHAIRMAN GRAHAM: It sounds like to me from Mr. Butler that this is probably not the best witness. Either Forrest was or Dr. --

MR. MOYLE: Taylor?

CHAIRMAN GRAHAM: -- Taylor would be.

MR. MOYLE: I'll tell you what, how about if I focus on the paper aspects of this.

BY MR. MOYLE:

Q Ms. Ousdahl, with respect to what FPL has to do under your understanding, they have to gather paper essentially as it relates to this Woodford Project, correct?

A I cannot testify as to what the commercial team does. I'm certain that it's more than gathering paper.

Q Okay. Well, let me maybe clarify what I mean. I mean you have to get these jibs from the PetroQuest, right?

A Yes, that would be the accounting for the investment.

Q I'm sorry. Maybe I didn't use the right term. So, you get jibs, and jibs are basically invoices?

A Yes.

Q And you aggregate those and put those together and then prepare a filing, you know, for this Commission where you say here's the cost that we incurred. We think it's prudent. Please pass this through to ratepayers.

Is that fair?

A That would be quite a shorthand version of what we would have to do with our invoices, yes.

Q It's after 8:00. I'm going for shorthand.

A All right.

Q And you were asked a lot of questions by Mr. Rehwinkel about what rights the Commission may have with respect to looking at papers and decisions and audits. This Commission wouldn't have the ability to audit anything related to the PetroQuest entity or the operating entity, correct?

A It cannot audit PetroQuest. It cannot audit our vendors. It cannot audit third parties. It can audit the entity it regulates.

Q The best evidence of weights that you may have by contract with PetroQuest for these records -- that would be in the contractual documents attached to Mr. Forrest's testimony as compared to your testimony; is that right?

A Yes. It's in the model form agreement that y'all spent quite some time talking about today.

Q The liabilities that would flow into FPL's subsidiary -- all of those liabilities are passed through to the ratepayers; is that right?

A All of the costs of operation, if being prudently incurred, would be incurred by customers, that's correct.

Q And that would include any liabilities, correct?

A Right. Assets or liabilities, working capital and common expenses.

Q You confused me when you said that you thought the limited liability company could capture some liability if it exceeded the costs of the contract?

A Are you referring now to my deposition testimony? Because you and I haven't talked about liabilities today or the LLC. I don't know if you want to refer to my deposition.

Q You know what, let's move on. Mr. Butler

used a term the other day when he was arguing before this Commission on a motion to dismiss. He said really what this is is capital substitution. Are you familiar with the term "capital substitution"?

A No, I need some context.

Q My interpretation of what he was talking about was that right now FPL does not earn a return, does not earn any money on fuel hedges. Is that your understanding?

MR. BUTLER: I can assure you that's an incorrect interpretation.

MR. MOYLE: I'm sorry?

MR. BUTLER: I can assure you that was an incorrect interpretation of my capital substitution point.

MR. MOYLE: Okay.

BY MR. MOYLE:

Q Let's forget your capital substitution point. Let me ask you this: You're responsible for the hedging filings that goes through the clause; is that right?

A No, but I'm aware of them.

Q And as they go through now, there's no return earned on the hedging program, correct? It's just a straight pass-through?

A On fuel hedging?

Q Yes, ma'am.

A There's no investment, so there's no earned return.

Q So, in this case, you know, this is being characterized as hedging. In this case, you, in effect, are now going to be earning a return on what has been described as hedging, correct?

A On our investment to provide the physical hedge to customers, yes.

Q You're the chief financial officer for Florida Power & Light, correct?

A No, I'm not.

Q Give to me your title.

A Chief accounting officer.

Q Chief accounting officer. I'm sorry. You have familiarity with the rating agencies? Part of what you do is interact with rating agencies?

A I have general familiarity, but I'm not interacting with the investors or rating agencies.

Q Well, with respect to your general familiarity, you're aware that PetroQuest is rated below investment grade?

A That's what you stated, yes.

MR. BUTLER: I'm going to object again. I don't think this is Ms. Ousdahl's testimony. I don't think it's fair cross examination of her testimony.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: In her deposition on Pages 132 and 133 -- and the deposition in evidence -- she talks about, "I think my understanding is PetroQuest has been in operation for some time. They have adequate liquidity."

She goes on to talk about some of the risk factors. Go to that, you know, the cost of capital may be quite high.

CHAIRMAN GRAHAM: Does she go into Wall Street or any of that stuff?

MR. MOYLE: I think she's talking about the 10Q which is a filing that's made with the SEC.

CHAIRMAN GRAHAM: All right. I'll allow the question.

BY MR. MOYLE:

Q I'll represent to you is that in answer to Interrogatory No. 35 -- this interrogatory is in evidence -- that your company said that S&P gave PetroQuest a B/stable rating and Moody's gave PetroQuest a B3/stable rating.

If I showed you the Moody's and the Standard and Poor's ratings with respect to what those meant,

would you be able to comment on that?
A No.
Q So, you have familiarity with it, but you just don't have the familiarity with respect to that level --
A Just general familiarity. My deposition was in response to you putting an SEC document in front of me and asking me questions. It certainly wasn't me proffering information about the financial health of PetroQuest.
Q No, I tried to keep your deposition out. And in response to a question from Mr. Rehwinkel, you said you understood that the market price can't be considered by PetroQuest or words to that effect. Did I get that right?
A I don't recall that.
Q Do you have an understanding whether PetroQuest in their obligation to drill has the ability to consider market price or not in this arrangement?
A I do not understand that to be the case, no.
Q You were shown a document by Mr. Rehwinkel. This is the Order 14546, fuel order.
A Yes.
Q And I wanted to ask you just a couple of questions about that. Is it your understanding that the

production costs -- the ratepayers are going to be charged production costs and those production costs are projected by Mr. Taylor and others to be relatively stable over time?

A I'm a little thrown by your "relatively stable." The costs do decline over time even during production, correct.

Q I'll tell you what, just assume for the purposes of our conversation that Mr. Taylor is going to get up here and say that he thinks the production costs are stable.

A Okay.

Q Okay. If he says that when he takes the stand, you would agree that the order that Mr. Rehwinkel showed you on Page 2, Paragraph 2, talks about prudently incurred fossil-fuel-related expenses which are subject to volatile changes. If Mr. Taylor says that the prices are stable, how would you reconcile that with the requirement of volatile changes in Paragraph 2, if you could?

A I think the only way you get to stable cost is if you're including depletion in those later years of production. And perhaps it's relatively flat line, but that's not the whole revenue requirement picture.

In addition, as I've already testified to this evening I believe, we're talking about the volatility created through additional investment which will be lumpy. So, I think we've established that there will be volatility if we're allowed to continue to pursue the strategy.

Q And you would say there's volatility as a result of the method of accounting; is that right?

A Investment profiles, the size of the investments, the timing of the investments and depletion, yes.

Q So, it would be your view that you could have volatility based on one year if FPL decides to invest 100 million and the next year they decide to invest 750 million that that would be a component of volatility that would make it eligible?

A Absolutely. I mean, there's some serendipity involved here. We don't get to just identify what we want to purchase.

Q These wells are not short-term opportunities. We talked about the production going for 30 years, correct?

A Correct.

Q And the order says, "The parties suggest that this flexibility is appropriate to encourage utilities to take advantage of short-term opportunities."

A Could you refer me, please.

Q Sure. Page 3 towards the bottom.

A Yes, I'm with you. I interpreted that to mean the opportunity is not going to exist for the next three years while we deliberate on whether or not we get to take advantage of the opportunity.

Q So, when it says short-term opportunities, the fact that this is going to go on for a long period of time -- you don't read that as addressing the fact that these operations are going to go on for 30 years?

A No, I don't think the policy of the Commission was intended to exclude advantageous purchase for customers that ended up being a long-lived asset.

Q So, you talked about the policy of the Commission. Do you have a view -- is the Commission limited in any way with respect to what they could do in terms of regulating in the public interest?

A Gosh, that's a challenging question. Are they limited -- could you narrow it down a little?

Q Sure. If FPL -- I'm just trying to test your understanding. You've given us some testimony about these lawyers. You're not a lawyer, right?

A No. No.

Q So, you're looking at these orders and trying to make interpretations of them; is that right?

A Based on the actions the Commissions have taken over the years and the written orders and the outcomes, yes.

Q Yeah. Would you defer to Mr. Deason on that point or should I continue asking you questions?

A He's clearly the expert on Commission policy.

Q Do you think the Commission could approve a solar plant under the same rationale that there's an opportunity for FPL to come in and buy the solar plant and that would reduce the fossil fuel as a quick opportunity. You've got to act now; that FPL should be able to come in and recover the costs of the solar plant under the fuel clause. And they put testimony in that says, hey, we can get a better deal for ratepayers because we're getting a great deal on this plant. We can produce solar panels for less money.

Would that be, in your opinion, something that could be recovered?

A I think that would be a big stretch of the interpretation of the order.

Q But the oil and gas is not, in your view?

A No, it's not, in my view.

Q Do you think this Commission should be cautious when approving multi-hundred million deals with parties who the Commission doesn't have jurisdiction

over?

A I think it's fundamentally the company's responsibility to make wise investment decisions. That's why we've tried to lay out guidelines and to seek approval from the Commission that they agree with the strategy. And it's our job to execute on that strategy. And yes, we would do that very carefully.

Q So, the answer to the question is you think, yes, the Commission should, likewise, be cautious when approving deals in the hundreds of millions of dollars with third parties?

A Yeah, I think the history that I've seen with this Commission is they take a lot of care with review and probing and stress testing the long-term analyses that we bring to them as do you all as intervenors.

Q And this doesn't involve your company, but you're aware that there have been recent disputes with third parties that this Commission has not had jurisdiction over in other contexts, Neal, Westinghouse?

Are you aware of any disputes related to those entities?

A Well, if -- no, I do not know what you're referring to specifically, but we're responsible for settling disputes and managing disputes associated with the vendors and contractual relationships that we have, not this Commission.

MR. MOYLE: Can I just have a second?

CHAIRMAN GRAHAM: Sure.

BY MR. MOYLE:

Q A final line of questioning.

A Okay.

Q Are you good?

A Yes, thank you.

Q FPL is outsourcing a lot of functions in this Woodford deal, correct?

A Yes, I think we're trying to find the right way to mitigate the risks of not having on day one the kind of experience that we would collectively like to have. Absolutely.

Q So, the accounting risk, the operation risks associated with oil and gas, the --

A Levering of talent of others is one tool we're using to supplement, you know, our thin experience, yes.

Q And so, with FPL, what exactly is it doing? Is it what we talked about with respect to what I'll put in quotes, the "paper gathering process"? That's what kind of FPL itself will be doing without outsourcing?

A I still struggle with your characterization. I mean, certainly, from a back-office perspective we're responsible for the financial accounting for the transactions which you might characterize as paper shuffling.

I think the commercial support that witness Forrest and his team will seek to supplement from the talented team at U. S. Gas won't be paper shuffling.

Q But that U. S. Gas effort to identify the good deals or bad deals -- that's delegated to U. S. Gas; is that right?

A No, I don't believe so, but you'd have to talk to witness Forrest about that.

MR. MOYLE: Thank you for your time.

THE WITNESS: You're welcome.

CHAIRMAN GRAHAM: Staff?

MS. BARRERA: No questions.

CHAIRMAN GRAHAM: Commissioners? Redirect?

MR. BUTLER: Thank you, Mr. Chairman, I'll be brief.

REDIRECT EXAMINATION

BY MR. BUTLER:

Q Ms. Ousdahl, you were asked by Mr. Rehwinkel a series of question regarding language in Order 12456 that includes the phrase "normally recovered through base rates." Do you remember that series of questions?

A Yes.

Q At the time that FPL proposed its investment in rail cars as a substitute for rail car leases for delivering coal to the Scherer Plant, were rail cars normally recovered through electric utility base rates?

A Not to my knowledge.

Q Mr. Rehwinkel also asked you whether Georgia Power company that's involved as the operator of Plant Scherer is regulated by the Georgia Public Service Commission. Do you remember that series of question?

A Yes.

Q Is FPL also involved in a joint venture with JEA for the SJRPP facility?

A Yes, we are.

Q And is JEA regulated by the Florida Public Service Commission or any other Public Service Commission in the same way that Georgia Power is by the Georgia PSC?

A No. They are a municipal operator.

Q Mr. Rehwinkel also asked you some questions about the level of expertise and successful efforts in accounting. Do you recall that?

A Yes.

Q Do you know whether U. S. Gas has expertise in successful efforts accounting?

A Yes, they do. I've levered the talent, time, attention and training of some of the accounting staff at U. S. Gas as I will continue to.

MR. BUTLER: If I can have just one second, please.

CHAIRMAN GRAHAM: Sure.

MR. BUTLER: That's all the redirect that I have. Thank you.

CHAIRMAN GRAHAM: Exhibits?

MR. BUTLER: Yes. We would move exhibits -- if I'm remembering correctly, it's 13 through 19.

CHAIRMAN GRAHAM: Any objections to entering exhibits 13 through 19? Seeing none, we will move those in. So, I take it No. 20 is redirect?

MR. BUTLER: It is, yes.

CHAIRMAN GRAHAM: Rebuttal, rather.

MR. BUTLER: Yes, rebuttal not redirect.

CHAIRMAN GRAHAM: Intervenors? I don't see any other exhibits that were offered.

MR. REHWINKEL: Mr. Chairman, I talked to staff on the break about this. Order 14546 -- I remembered that there was something weird about it online. And if you go online and you pull the order up, it's got an extended area service telephone order piece involved in it.

So, I would just ask in an abundance of

caution, if we could make the copy that we passed out, which was the Commission's own document, a part of the record. I'm not trying to break with tradition or make Ms. Helton mad, but I would just ask if we could give that document an exhibit number and move it into the record.

CHAIRMAN GRAHAM: I don't have a problem with that. We would give it Exhibit No. 65. I appreciate the fact that it may not be something readily available online, and it's difficult to get. And if we have it as part of this hearing, it will be easier to put your hands on it.

MR. REHWINKEL: Thank you. I appreciate that, and I would move it into the record.

MS. HELTON: And just to make the record clear, I have asked Ms. Craig, our administrative assistant to get in touch with Lexus, because I do agree, there is something really weird about the order on Lexus. So, hopefully that can get squared away for the future.

CHAIRMAN GRAHAM: Okay. May Ms. Ousdahl be excused for the moment?

MR. REHWINKEL: Works for me.

CHAIRMAN GRAHAM: Dr. Taylor, the last two witnesses have been talking about you, so welcome.

MR. REHWINKEL: Dr. Taylor has been previously sworn.

Whereupon,

DR. TIMOTHY TAYLOR

was called as a witness, having been previously duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. REHWINKEL:

Q Dr. Taylor, would you please state your name and business address for the record?

A Timothy Dale Taylor, 601 Travis, Houston, Texas, Suite 1900.

Q And by whom are you employed and in what capacity?

A NextEra Project Management, gas infrastructure as chief technical officer.

Q Have you prepared and caused to be filed in this document 24 pages of prefiled direct testimony?

A Yes.

Q On June 25, 2014, in this proceeding?

A Yes.

Q Do you have any changes or revisions to that testimony today?

A No.

Q So, if I ask you the same questions contained

in your direct testimony today, would your answers be the same?

A Yes.

MR. REHWINKEL: Mr. Chairman, I'd ask that Dr. Taylor's prefiled direct testimony be inserted into the record.

CHAIRMAN GRAHAM: We'll insert this witness' pre-filed direct testimony into the record as a witness.

(Whereupon, prefiled testimony was inserted.)

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tim Taylor. My business address is 601 Travis, Suite 1900, Houston, Texas, 77002.

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

A. I am employed by NextEra Energy Project Management, LLC, as the Chief Technology Officer of the Gas Infrastructure and Development business unit ("Gas Infrastructure").

Q. Please describe your educational background and professional experience.

A. I have been actively involved in the oil and gas industry for over 40 years. I hold Bachelor of Science, Masters of Science and PhD degrees in Petroleum Engineering from the University of Texas at Austin. I am a licensed professional engineer in the state of Texas.

I have been with Gas Infrastructure since August of 2012. Prior to that, I was Chief Operating Officer of Texas American Resources. I was also a Professor in the Petroleum and Geosystems Engineering Department at the University of Texas at Austin where I taught oil and gas reserve determination and economics and petrophysics. Prior to that, I was Chief Operating Officer of SOCO International, plc, an international oil and gas company. I have also served in various capacities with Snyder Oil Company and Gulf Oil Company and was President and CEO of Taylor, Caudle & Associates, a consulting firm specializing in reserves and economics. Exhibit TT-1 is a copy of my resume.

Q. Please describe your duties and responsibilities in your current position.

A. As Chief Technology Officer, I am responsible for evaluating oil and gas acquisition opportunities, supporting operations in evaluating drilling and lease acquisition proposals from outside operating partners and maintaining internal reserves and economics database. I am responsible for preparing internal reserve estimates, using Securities and Exchange Commission ("SEC") and Society of Petroleum Engineers reserve definitions and guidelines.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits which are attached to my direct testimony:

- TT-1 Resume of Dr. Timothy D. Taylor
- TT-2 Difference Between Conventional and Unconventional Natural Gas Deposits
- TT-3 Historic and Projected Growth of Shale Gas Volumes
- TT-4 "Behind-Pipe" Zones
- TT-5 Map of the Woodford Shale
- TT-6 Location Map of the PetroQuest Acreage
- TT-7 EUR Type Curve Map
- TT-8 Projected Drill Schedule Map
- TT-9 Volume Forecast for FPL (confidential)

- TT-10 Forrest A. Garb & Associates Report (confidential)

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

A. The purpose of my testimony is to:

(i) Provide an overview of the gas production industry as background for the proposed investment in gas reserves and the production of natural gas in the Woodford Shale region to meet a portion of Florida Power and Light Company's ("FPL") natural gas requirements (the "Woodford Gas Reserve Project," "Woodford Project" or the "Project");

(ii) Summarize the volumes of natural gas that can be recovered underneath the 19 sections (12,160 acres) in Pittsburg County, Oklahoma, operated by PetroQuest Energy, LLC ("PetroQuest") that comprise the Woodford Project;

(iii) Describe and support the analysis of the production rate at which these reserves can be recovered using the drilling schedule provided by PetroQuest;

(iv) Present the estimate of the total amount of gas that is expected to be economically recovered from the Woodford Project, referred to as the Estimated Ultimate Recovery ("EUR");

(v) Demonstrate the reasonableness of Project estimates in items ii, iii and iv above by comparing them to an independent, third party study; and,

(vi) Discuss the detailed monthly forecast of volumes of natural gas to be recovered from the Project and provided to USG Properties Woodford

I, LLC (I will refer to both this entity and Gas Infrastructure as "USG") and FPL.

Q. Please provide a brief summary of your testimony.

A. My testimony provides an overview of the geology and technology of the gas production industry relevant to the proposed Woodford Project, including a description of natural gas and other hydrocarbons, how they are formed, and how natural gas reserves are categorized. I provide an overview of the Woodford Shale, where the Woodford Project is located.

My testimony then examines the reserves recoverable from the wells and leases operated by PetroQuest that will be part of the Woodford Project. I discuss the economic analysis that determined the EUR of each existing or to be drilled well and the detailed monthly volume forecast of these reserves used for purposes of assessing the Project. This analysis consists of the following steps: (i) identification of the wells and leases being offered for sale by PetroQuest, (ii) confirmation that PetroQuest is the operator of record of the wells and leases being offered, (iii) attainment of records from PetroQuest relating to working and net revenue interest, historical operating costs, historical drilling and completion costs, historical production volumes from existing wells, (iv) construction of production type curves based on nearby well performance and on the specific producing wells in the acreage being offered, and (v) inclusion of this information, along with FPL's forecasted gas pricing, into an oil and gas reserves and economics software model, PHDWin, from which gas volume forecasts were generated. A third-party engineering firm, Forrest A. Garb & Associates, Inc., was engaged by FPL to perform an independent analysis.

Based on the results of my analysis, I conclude that the Project is economically viable and commercially attractive. I have also provided the results of my analysis to FPL, which uses it as an input in projecting customer savings for the Project.

II. OVERVIEW OF THE GAS PRODUCTION INDUSTRY

Q. Please provide a brief description of natural gas and explain the difference between "wet" and "dry" natural gas.

A. Natural gas and other fossil fuels are hydrocarbons. Hydrocarbons are formed by the decaying remains of plants and animals, mostly microscopic marine life, from millions of years ago. The physical process in which this organic matter is converted into hydrocarbons is known as catagenesis, and it occurs deep within the earth's crust. The pressure and temperature at which catagenesis occurs will impact the type of hydrocarbons that are formed. For example, deeper deposits with higher pressure and higher temperature favor the formation of lighter hydrocarbons (natural gas), while shallower deposits tend to contain heavier hydrocarbons that are in liquid form (i.e., oil).

Natural gas primarily consists of methane, but other, heavier hydrocarbons such as ethane, propane, butane, and pentane may be present as well. These heavier hydrocarbons are commonly called natural gas liquids ("NGLs"). When natural gas contains predominantly methane, it is commonly referred to as "dry" gas. In reality, there is rarely pure, 100% methane even in "dry gas" formations, as small amounts of NGLs and other impurities are almost invariably present. Conversely, natural gas containing significant fractions of the other previously mentioned hydrocarbons, or NGLs, is commonly referred to as "wet" gas.

Upon extraction of wet gas from the well, the entire volume is sent through a processing facility to separate and capture the NGLs, thus transforming the "wet" gas into "dry" gas. NGLs collected during processing may require further processing or separate transport depending on their specific contents. As I will discuss below, there are markets for the NGLs; thus, the owner of a gas reserves project will realize value from the extraction and processing of NGLs as well as methane. The ratio of dry gas to NGLs is one of several factors in assessing the commercial viability of a formation. In addition to dry gas and NGLs, it is not uncommon for oil to also be produced simultaneously from the wells.

Q. Describe the gas that is used for purposes of generating electricity in power plants.

A. Natural gas-fired generation facilities run on pipeline quality dry gas, which is fed directly into the plant. "Pipeline quality" natural gas has specific characteristics for heat content, moisture and NGLs and typically requires a minimum of 85% methane. Pipelines maintain gas quality standards to ensure the uniformity and usability of the natural gas they transport so that their customers, including FPL, can operate gas-fired equipment safely and efficiently.

Q. What are the different types of underground formations that can contain natural gas?

A. Historically, the most common formation that was drilled to extract natural gas has been what is characterized as "conventional." These formations are geologic deposits characterized by naturally occurring pockets where natural gas collects and is trapped by an impervious layer of rock. This natural gas can be either "associated," which means it resides in conjunction with an oil deposit, or "non-associated," which means there is no oil associated with the gas deposit.

Currently, the fastest growing source of natural gas is from unconventional formations. The most common unconventional formations are shale gas, tight gas, and coal-bed methane. These formations are characterized by natural gas that is trapped in porous rocks that have little permeability and, therefore, cannot usually flow in commercial quantities without special drilling and completion techniques.

The graphic provided in Exhibit TT-2, produced by the U.S. Energy Information Administration ("EIA"), illustrates the difference between conventional and unconventional natural gas deposits.

Q. How has unconventional shale gas affected the natural gas industry?

A. Advancements in technology related to horizontal drilling and completion techniques have created access to large deposits of shale gas that were previously uneconomical to produce. This has rejuvenated the natural gas industry in the United States, which contains some of the largest shale gas reserves in the world. Shale gas is the fastest growing source of supply in the United States over the past 10 years and its emergence has pushed gas prices to historical lows. Specifically, over that same time frame, the percentage of shale gas that contributed to domestic production grew from less than 5% to over 30% of total production. The graph provided in Exhibit TT-3, from the EIA, depicts the historic and projected growth of shale gas volumes.

Q. What is meant by the term "gas reserves"?

A. Gas reserves represent the quantity of gas than can be economically recovered from a reservoir (conventional or unconventional). Recoverable gas reserves do not typically equal 100% of the gas in the reservoir due to variations in rock quality, porosity, permeability, pressure, the number of wells and their drainage areas, economic considerations, and other factors. Estimated volumes of gas reserves can change with advancements in technology that can reduce drilling and operating costs and changes in commodity pricing that make additional volumes of gas economically recoverable.

Q. What method typically is used to estimate the amount of gas that is physically recoverable from shale reserves?

A. The decline curve analysis method is the most reliable and commonly used method to estimate recoverable gas from shale reservoirs when abundant historical production data is available, as is the case for the Woodford Project.

Decline curve analysis is a reserve estimation method that uses the shape of the decline in historical production to forecast future volumes of gas by applying mathematical equations that describe the shape of the decline curve and the constantly changing rate of decline. These equations are hyperbolic in nature and this method is, by far, the most accurate in predicting future production when sufficient historical production is available. While actual performance can vary from estimates significantly for individual wells, decline curve analysis has proven very reliable and accurate in predicting the average performance for wells within a reserve. As will be discussed later in my testimony, decline curve analysis was used to forecast future reserves because there are many wells in the PetroQuest area with sufficient historical production to justify the application of this method. The results of the methodology are inserted into the economic model that determines the EUR of the reserves. I will discuss the EUR concept in greater detail below.

Q. Are gas reserves classified on attributes other than quantity?

A. Yes. In addition to quantifying the amount of gas reserves, companies also characterize the quality of reserves. In this context, "quality" refers to the likelihood, based on currently available information, that the full estimated reserve quantity can be economically produced. The industry uses as its frame of reference for classifying gas reserves three standard categories defined by the SEC for public company reporting.

- Proved reserves ("Proved") are those reserves with reasonable certainty (90% probability) that the predicted quantity of gas can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. This reserve category can be further subdivided into three sub-categories.
  - Proved Developed Producing ("PDP") reserves are in currently operating wells that have reasonable certainty of continuing production.
  - Proved Developed Non-Producing ("PDNP") reserves are reserves that have been (i) drilled and completed but not yet producing due to pending pipeline connection, surface facilities or other factors that do not require substantial capital investment relative to drilling the well or, (ii) hydrocarbon bearing zones that are "behind pipe," which generally means productive zones up the wellbore from the primary completion zone (see Exhibit TT-4). These zones will be equipped for

production at some point in the future, typically after the currently producing zone is depleted.

  - Proved Undeveloped ("PUD") reserves are in well locations in a proved area that require additional capital investment to drill and complete the well in order to extract the gas.

- Probable reserves ("Probable") are those reserves with some uncertainty (50% probability) that the predicted quantity can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. These reserves may appear productive by analysis but are outside the areas defined as proved and lack definitive tests.
- Possible reserves ("Possible") are those reserves with high uncertainty (10% probability) that the predicted quantity can be commercially recoverable under current technical, contractual, economic, and regulatory conditions. These areas appear to contain hydrocarbons but are outside of the area assumed to be probable.

Q. Are projects and transactions involving gas reserves priced solely on the basis of the three levels of reserve categories in the SEC reporting requirements?

A. No. Projects and transactions involving gas reserves are priced on the basis of several factors, which I discuss in more detail below. But with regard to the quality of reserves, obviously there is a range of estimates anywhere from below 10% to more than 90%. The actual estimate, not the SEC category, is typically used in pricing a transaction.

Q. Can there be substantial value in reserves that are classified as Probable and Possible?

A. Definitely. While Proved reserves provide more immediate certainty around production, there is substantial value in developing projects whose quality of reserve estimates also include Probable or Possible reserves. The distinction between the actual categorization of a reserve as Proved, versus Probable or Possible can be quite narrow and evolve over time. For instance, by SEC definition, a PUD location may be only one location away from an existing PDP well. In that instance, the next location away from the PUD location would be defined as Probable. When the PUD location is drilled, it immediately gets reclassified as a PDP well. Therefore, by definition, the adjacent Probable location automatically becomes a PUD location. So, by this example, we see that the SEC reserve classification applicable to a well can evolve simply by the normal course of developing a well field.

In many instances, it is necessary and/or desirable to drill Probable or Possible locations before they have been converted to PUD locations in order to take advantage of efficiencies in drilling rig utilization. In other words, if a surface location is capable of accommodating multiple wells, it would be inefficient to drill only the PUD locations, move the rig off to wait for production to be established in those wells, then move the rig back to that location to drill the

Probable or Possible locations. In other instances, it would make sense to drill Probable or Possible locations when there are no adjacent PUD locations, in order to extend the limits of the field based on geophysical interpretations of seismic data which would give a high level of confidence that the Probable wells would perform similarly to the PUD wells. Both of these scenarios apply to the Woodford Project, where we have three-dimensional seismic data that covers the entire Area of Mutual Interest ("AMI") for the Woodford Project.

By combining a thorough analysis of available technical data, project investors make informed decisions on investing in Probable and Possible reserves based on the economics of the project. Probable and Possible reserves represent the future growth of a project. As wells are drilled, these categories get converted to Proved reserves as described above. A typical gas reserve investment portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of the major SEC categories of Proved, Probable and Possible.

Q. What are some of the factors that affect the commercial value of shale formations?

A. Broadly speaking, there are three main factors that determine the value of any natural gas resource in the marketplace: market value of the commodity, the amount and composition of the commodities that can be extracted, and the cost to extract that commodity. Two of these factors, amount and composition of the commodities and cost to extract, will be specific to each shale region and can be evaluated more granularly.

Regarding the amount and composition of the commodities, each shale region contains a unique composition of hydrocarbons. In addition to natural gas and NGLs, it is possible for oil to coexist in the reservoir which would be produced along with the natural gas. The volume of NGLs extracted from wet gas varies according to its composition. When NGLs are present, both the NGL volumes and the resulting volumes of dry natural gas, after extraction of the NGLs, are projected and included in an economic analysis.

Regarding the cost of extracting the commodity, each unconventional resource has unique geologic or geographic characteristics that will affect economic value. A particular formation's depth, thickness, and rock type will affect the capital expenditures ("CapEx") required to drill and complete a well. In addition, there are ongoing operating expenditures ("OpEx") associated with the production of the natural gas.

Q. How does the presence of NGLs and/or oil affect the economics of a well?

A. As previously mentioned, NGLs commonly exist as a component of natural gas. Although NGLs and natural gas are extracted in conjunction with one another, NGLs have a different set of uses and hence a different market price. The largest uses of NGLs are in petrochemicals, gasoline components, and heating. Pricing for NGLs is closely correlated with the price of oil and NGLs usually sell at a percentage of the price of crude oil. Based on current market pricing, NGLs are trading at a significant premium to natural gas on a unit equivalent basis. For this reason, many producers have focused their development efforts on formations that contain a higher concentration of NGLs. Said another way, the presence of NGLs in the volumes extracted from a well can effectively lower the per unit cost of the natural gas produced, as the increased value of NGLs relative to natural gas subsidizes the cost of producing the natural gas. Similar considerations apply if oil can be extracted from a well along with natural gas.

Q. Would it be appropriate for FPL to consider future projects in formations that contain NGLs and/or oil as well as dry gas?

A. Yes. While the Woodford Project is not anticipated to have economically significant quantities of NGLs or oil, each project opportunity should be evaluated on its economic merit. For example, because NGLs currently trade at a premium relative to natural gas, a wet gas project can be economically viable with lower natural gas production volumes than are needed to justify a dry gas project. With producers focusing on regions with higher ratios of NGLs to methane, FPL would be substantially limiting the opportunities with potential counterparties and may encounter difficulty in executing additional transactions until the gas price forecast has increased to make dry gas projects more economical. Moreover, the significant value in NGLs can lower the effective cost of the methane that is produced. So it would truly depend on the specifics of the project opportunity.

III. OVERVIEW OF WOODFORD SHALE

Q. Would you please provide a brief description of the Woodford Shale?

A. The Woodford Shale lies underneath most of the state of Oklahoma and ranges from 50 feet to 300 feet thick. The region of the Woodford Shale in the Arkoma Basin of southeastern Oklahoma, where the AMI acreage with PetroQuest is located, covers approximately 2,900 square miles and lies between 6,000 feet and 13,000 feet beneath the surface. The extent of this shale in this region is shown in Exhibit TT-5. It is an organic-rich shale of Devonian age that was deposited about 350 to 400 million years ago. It is characterized as a low permeability silica-rich shale rock with relatively high porosity. Porosity controls the amount of gas that can be stored in the rock and permeability controls the ability of the rock to allow fluid to flow through the pore spaces (i.e., a measure of the connectivity of the pores). The Woodford Shale in this region where the AMI acreage is located produces dry natural gas.

The oil and gas industry has long known the Woodford Shale to be the source rock for many of the conventional productive deposits. The first gas production from the Woodford Shale was recorded in 1939 from vertical wells. The first horizontal wells were drilled in 2004 and today, with the advent of technological advances in horizontal drilling and completion methods, there are approximately 2,000 wells producing from the formation.

Around 75% of those are horizontal wells. Many oil companies like Devon Energy, Newfield Exploration, Chesapeake Energy, Antero Resources, Continental Resources, PetroQuest Energy, XTO Energy and others are actively drilling the Woodford Shale.

Q. Please describe PetroQuest's involvement in the Woodford Shale and specifically in the AMI for the Woodford Project.

A. PetroQuest has drilled over 120 wells in the Woodford Shale and has established itself as an efficient, low cost developer of natural gas reserves. The production history from the wells in and around the AMI supports the application of the decline curve analysis method discussed earlier for the Woodford Project. The map shown in Exhibit TT-6 shows the 19 sections of the AMI being offered by PetroQuest. The horizontal lines within these sections represent individual horizontal wells that have been drilled in this area of Pittsburg County, Oklahoma. There are 19 horizontal Woodford wells within the AMI. USG has been a partner of PetroQuest in this area since 2010 and participated in drilling 17 of these wells, the other two having been drilled before the partnership was formed.

IV. ASSESSMENT OF WOODFORD PROJECT RESERVES

Q. Have you evaluated the gas reserves in the Woodford Project?

A. Yes. I estimated the future volumes of natural gas reserves that could reasonably be expected to be recovered from the wells to be drilled in the 19 sections and provided FPL with a monthly volume forecast.

Q. Why is it necessary to perform a reserve assessment for the Woodford Project?

A. The assessment of reserve projections is necessary to understand the future volumes of natural gas available in order for FPL to make its own assessment of the economic viability of the Woodford Project.

Q. How are reserves for the Woodford Project categorized for the purpose of the assessment?

A. There are 38 remaining horizontal well locations to be drilled in the AMI. Of these, 25 are in the PUD reserve category, meaning they are Proved reserves that have yet to be drilled but are supported by nearby producing wells. 13 of the locations are in the Probable reserve category. However, these locations are immediately adjacent to sections that have existing producing wells in the AMI. The distribution and performance of the existing wells gives us a high level of confidence that the Probable wells will perform similarly to the PUD wells.

Q. Please describe the reserve assessment that you performed for the Woodford Project.

A. My analysis consisted of the following steps:

(i) A performance analysis was conducted on the PDP wells in the AMI. The production data from these and other wells around the AMI were used in our decline curve analysis;

(ii) The result of the performance analysis indicated that there were differing levels of performance for the eastern area of the AMI versus the western area of the AMI. Therefore, for PUD and Probable reserves, two type curves were constructed, one for each area that matched the average performance from the nearby PDP wells;

(iii) These type curves were then applied to the remaining undrilled locations in each type curve area as shown in Exhibit TT-7. This exhibit also shows the EURs for each of the 19 existing wells and the EURs for the two type curves;

(iv) The PUD and Probable volume forecasts were fed into PHDWin, an industry oil and gas decline curve analysis and economic software program. A projected drilling schedule was applied according to the drilling schedule shown in Exhibit TT-8, assuming two rigs would be utilized to drill all of the wells in the AMI. Both rigs were assumed to begin drilling on September 1, 2014. The solid purple lines represent the horizontal laterals for the PUD locations and the dashed purple lines show the horizontal laterals for the Probable locations.

(v) An examination was conducted of PetroQuest's Lease Operating Statements, ("LOS") and USG's LOS from the wells in which USG and PetroQuest are partners in the AMI. These are industry-standard documents prepared by operating companies to capture their monthly operating costs, production taxes, transportation fees, and other costs. These costs were then fed into PHDWin along with FPL's natural gas price forecast supplied;

(vi) The resulting economic analysis determined the economic limit of the production from each well which, in turn, determined the EUR from each well; and

(vii) A detailed monthly forecast of the combined volumes of natural gas production was then provided to FPL.

This is an industry accepted method of reserve forecasting.

Q. What is the source of the inputs to your analysis?

A. The operating costs for the analysis were taken from the actual operating costs in PetroQuest's and USG's LOSs. The capital cost for the undrilled wells was provided by PetroQuest. Volume projections came from USG's decline curve analysis on PDP wells and from the type curve for PUD and Probable wells. The drilling schedule came from an internal USG analysis that I performed. All these items were deemed reasonable based on our experience in the area.

Q. What are the results of your analysis?

A. My analysis shows that the Woodford Project is economically viable. There are robust reserves available with a high expectation of natural gas recovery.

We determined the average EUR of the undrilled wells in the AMI to be 6.6 BCF/well. Relative to the projected costs for well development, these are economically attractive volumes. It was assumed that the transfer of ownership from USG to FPL would occur on January 1, 2015. Using the drilling schedule described earlier, we combined the production to be recovered from all wells subsequent to that date into one monthly volume forecast, as shown in Confidential Exhibit TT-9 and this forecast was provided to FPL.

Q. Did you also consider an outside consultant's reserve assessments in your analysis?

A. Yes. In addition to the internal analysis I performed for FPL of all of the reserves, FPL engaged an independent consulting firm to perform a third-party analysis. FPL chose Forrest A. Garb & Associates, Inc. ("FGA"), a trusted engineering firm with experience in the Woodford Shale. The FGA report is attached as Confidential Exhibit TT-10.

The average EUR from the FGA analysis of 6.62 BCF/well is extremely close to our internal estimate of 6.61 BCF/well and support~~s~~ the conclusion that the reserves are economically viable at the levels we estimated.

Q. What is your overall conclusion regarding the Woodford Gas Reserve Project?

A. The Woodford Gas Reserve Project is an economically viable and commercially attractive natural gas recovery project, operated by an industry leader in this region.

Q. Does this conclude your direct testimony?

A. Yes.

BY MR. REHWINKEL:

Q Dr. Taylor, did you also sponsor Exhibits TT-1 through TT-10 as part of your direct testimony?

A Yes.

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

A No.

Q Are they true and correct, to the best of your knowledge and ability?

A Yes.

MR. REHWINKEL: I'd just note for the record that those are identified as 21 through 30 in the comprehensive staff exhibit list.

BY MR. REHWINKEL:

Q Dr. Taylor, do you have a summary of your direct testimony?

A I do.

Q Would you please give it at this time.

A Yes, thank you. Good evening, Mr. Chairman, Commissioners. I was asked by FPL to conduct an analysis of the potential reserves that could be produced from the Woodford Project in the Arkoma Basin of the Woodford Shale. The Woodford Shale lies underneath most of the state of Oklahoma.

It has been long known by the oil and gas industry that the Woodford Shale is the source rock for any other hydrocarbon boring zones in the region. The first production from the Woodford Shale was recorded in 1939 from vertical wells. Since then, there have been many, many wells drilled in the Woodford Shale.

The first horizontal wells were drilled in approximately 2003. And with the advent of production from production technology, increases from hydraulic fracturing and horizontal drilling, there have been more than 2,000 wells drilled in the Arkoma Basin at this time. 75 percent of those are horizontal wells.

Many oil companies such as Chesapeake Energy, Newfield, Antara Resources, Continental Resources, PetroQuest Energy and EXCO Energy and others are active in the Woodford Shale. The area of mutual interest acreage as far as FPL's proposed joint venture partnership with PetroQuest is located in the Arkoma Basin in southeastern Oklahoma.

It covers approximately 2900 square miles and occurs between 6,000 and 13,000 feet below the surface. It is characterized as a silica-rich shale rock that was deposited about 350 to 400 million years ago in the Devonian period.

The rock has relatively high porosity which controls the storage capacity for gas in the rock but relatively low permeability. The permeability controls the ability of the rock to allow fluid to flow through the porous spaces.

Production and exploration in the Arkoma Basin has been going on for decades. An assessment of the reserve production for FPL's proposed Woodford Project is necessary to understand the future volumes of natural gas available. In turn, that information allows FPL to make its own assessment of the economic viability of the Woodford Project.

FPL's proposed joint venture partner PetroQuest has drilled over 120 wells in the Arkoma Basin. To date in the area of mutual interests, there have been 19 wells drilled in 19 sections.

U. S. Gas owns an interest in 17 of those 19 wells. All 19 of those wells are still producing today. Some of them were drilled as early in 2010. There are 38 remaining locations to be drilled in the area of mutual interest, all of which are immediately adjacent to sections that contain producing wells.

Thus, these 19 wells have essentially de-risked the remaining 38 wells to be drilled in the area of mutual interest. That's because the distribution and performance of those existing wells gives us a high level of confidence that we can accurately forecast the production that would come from those wells.

25 of those 38 wells are in the approved category and the rest in the probable category. These are industry-standard classifications that indicate to us that there is a high probability that the gas reserves projected will be actually recovered under current technological, contractual, economic and regulatory conditions.

Using industry-standard evaluations methods and based on more than 35 years of experience, I examined the production from the producing wells in the area of mutual interest. I determined that two types curves, one in the east of the AMI and one in the west, were appropriate for estimating the performance of future wells to be drilled.

These type two type curves were developed based on data from the existing wells and were then applied to the remaining undrilled locations in each type curve area.

I gathered capital costs, operating costs, price differentials and other economic data and applied these to the undrilled locations using PhdWin, an industry-accepted decline curve analysis and economic software program.

The resulting economic analysis determined the economic upward limit of the production from each well and, in turn, determined the estimated ultimate recovery which is the estimate of the total amount of gas that is expected to be economically recovered from the Woodford Project.

From this analysis, I determined the Woodford Project to be economically viable. The robust reserves available with a high expectation of natural gas recovery are then provided to FPL, a forecast of monthly volumes from these wells from which they could make their own economic analysis.

My results were confirmed by respected third-party engineering consulting for Forrest A. Garb & Associates. In conclusion, the Woodford Gas Reserve Project is an economically viable natural gas recovery project operated by an experienced operator, PetroQuest, in this region.

That concludes my summary. Thank you.

CHAIRMAN GRAHAM: Thank you, Dr. Taylor. I tender the witness for cross examination.

MR. TRUITT: Thank you, Mr. Chairman. John Truitt with OPC.

CROSS EXAMINATION

BY MR. TRUITT:

Q Good evening, Dr. Taylor.

A Good evening.

Q I just have a few questions on direct, not too much. Now, in your decline curve analysis in your experience, isn't that correct that generally you personally want to see from a minimum of several months to over a year to perform your analysis?

A That is correct, although it's different for each project. But that is, in general, true.

Q So, you would agree that there are variances within place as we saw here in eastern and western?

A Sure, there can be variances in place.

Q Now, when you take -- let's just use the hypothetical of a year. I know that's not the case here, but as a hypothetical for a year, you would take that information and then extrapolate it out over -- it could be more than a decade, correct, for a tight curve, a decline curve?

A If that production data has told me the decline scenario that it's going to assume, then that's true, yes.

Q Now, isn't it true in the analysis of this Woodford Project you used data from PetroQuest or publicly-available data, correct?

A Both, yes.

Q And you mentioned the Forrest A. Garb & Associates that performed an analysis. Isn't it correct that it's not necessarily an industry standard to engage a third-party analysis?

A Again, it's an individual preference from the company that's making the investment as to whether or not they want to have a third-party analysis. And in many cases, the third-party consulting analyses are used and in some they're not.

Q On that --

MR. MOYLE: Mr. Chairman, again, I had indicated I was going to object to this Garb Report. I don't want to waive the objection. We'll deal with it when the exhibit comes in, if that's all right, but I don't want to interrupt the cross by continuing to object.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: Thank you.

BY MR. TRUITT:

Q You just stated that depending, sometimes the company asks for it. Are you aware of any requirement from the Florida Public Service Commission that there be a third-party analysis?

A No, I'm not.

Q Do you know of any governing body or regulatory entity in this matter that requires third-party analysis?

A In Florida?

Q Anything involving this even in Oklahoma, if you know that.

A Well, if it's a publicly-traded company, the SEC requires a report to be filed by a third party.

Q Now, I want to look at your Exhibit TT-10, the Forrest A. Garb real quick. Do you have that with you?

A Yes.

Q Now, I understand it's confidential and we went through this in a deposition, but you're going to hear me ask the same type questions. I'm asking you to look at Page 3 of 30 to start with.

A Of the Forrest Garb report?

Q Yes, of your TT-10. It's labeled 3 of 30 in the top right-hand corner, sir.

A Okay.

Q Second paragraph if you'll look at the last sentence of the second paragraph starting with the word "the." You would agree that that statement is correct?

A (Examining document.) The last sentence of the second paragraph says discounted revenue figures were calculated using a discount factor of 10 percent.

MR. BUTLER: Dr. Taylor because this is a confidential exhibit, let's try to answer sort of generically his questions. I know that you are not as familiar with the procedure here, but we're trying to keep the record as clear of confidential context as possible.

BY MR. TRUITT:

Q I'm sorry. To be clear, I'm on Exhibit TT-10 Page 3 of 30 in the top right hand corner. It's in the second paragraph under the engineering category. At the bottom of the page you have Page No. 2. So, we've got two different page numbers on the same thing. That may be the confusion.

I apologize. On to the engineering section, the second paragraph, last sentence, starts with "the." Again, it's confidential. I just want to confirm that you would agree that that sentence is correct.

A Yes.

Q Okay. Now, I'm going to flip to Page 26 of 30 according to the numbering in the top right-hand corner. And at the bottom of the page it says Attachment D-1?

A Yes.

Q Again, confidential. I'm looking at the

statements, two sentences contained in No. 5. I'll ask again: Would you agree that those statements are correct?

A Yes.

MR. TRUITT: No further questions.

CHAIRMAN GRAHAM: Retail Federation?

MR. LAVIA: No questions, Mr. Chairman.

MR. MOYLE: I have some questions. I was hoping I could get some help with an exhibit as well.

CHAIRMAN GRAHAM: Sure. After 6:00 we only have one staff person.

MR. MOYLE: I think everybody has a copy at this point.

CROSS EXAMINATION

BY MR. MOYLE:

Q Mr. Taylor, I'm showing you what's already in evidence as response to Interrogatory No. 75. You're familiar with this; are you not?

A No.

Q Not in any way, shape or form?

A No. I did not prepare this answer.

Q There's a table here that talks about the Woodford costs from 2010 to 2013. You also talk about the production costs as it relates to the project in

question, correct?

A Yes.

Q What are the production costs of the project in question, your projected production costs?

A Are you referring to the operating costs?

Q Just the all-in costs that are going to be submitted to Ms. Ousdahl to be included in a fuel clause filing.

A Those costs are approximately $2,300 per month per well plus the water disposal cost.

Q And can you break that down on a BTU basis?

A No, sir, that's on a per well basis. Dollars per well/per month.

Q So, this exhibit that's in evidence -- I mean, you're not able to even look at it and comment on the fact that at least it appears to show that from 2010 to 2013 that the average price of production for the Woodford area was above the NYMEX Henry Hub price?

A Are these prices? These are not costs. These are prices.

Q The question says, "Please refer to Page 6, Paragraph 10, of the petition. For the five-year period of time 2009 to 2013 provide a table comparing the cost of production from Woodford Shale gas reserves to market prices."

A Well, there are no units on this table, so I'm not sure what it's referring to. Is that dollars per MCH?

MR. BUTLER: Mr. Chairman, I'd just like to note for the record that this interrogatory answer was sponsored by Mr. Forrest. He would have been far better suited to answer questions about it than Dr. Taylor who doesn't have a role in sponsoring it.

MR. MOYLE: This is my bad on that. I apologize. I'll try to pick it up with Mr. Forrest when he comes back up. I'm sorry, Mr. Taylor.

MR. BUTLER: Mary Anne, is that a legal term, "my bad"?

MS. HELTON: No, but I'm sorry --

MR. MOYLE: I do have another exhibit. Hopefully, this one will work out better than the last one.

CHAIRMAN GRAHAM: Mr. Moyle, we'll give this an exhibit number of 66. Do you have a copy?

MR. MOYLE: Do you have a copy, Mr. Butler?

MR. BUTLER: I do.

BY MR. MOYLE:

Q Mr. Taylor, I've handed you what I'll represent is an excerpt of the PetroQuest 2013 annual

report, and the excerpt relates to risk factors. We talked about this in your deposition.

Just as a summary, you don't disagree with any of the risk factors set forth in this exhibit, correct?

A I don't disagree that they've identified these as potential risks.

Q Right. And they made this filing with the SEC, correct?

A That's correct.

Q And I want to ask you some questions about certain of these risk factors, if I could. On Page 28 down towards the bottom and in bold it says, "Operating hazards may adversely affect our ability to conduct business." And then they -- the first bulletpoint they said unexpected drilling conditions including blowouts, cratering and explosions.

We're all kind of new to this oil and gas business here, and I was hoping that you could help out with what a blowout is.

A A blowout general happens during the drilling of a well when the pressure in the reservoir exceeds the mud weight and the hydrostatic head of the mud weight in the well bore. It blows all the mud out of well bore while it's being drilled and followed by gas and/or oil.

Q And I take it that's a bad thing?

A That's not a good thing, no, sir.

Q Do people get hurt when that happens?

A They could, yes, unless they can run, very, very fast.

Q And when that's happening, does oil kind of spill all over the place in an uncontrolled basis to the extent that there's oil?

A If it's an oil well, that could certainly happen, yes.

Q If it's a gas well, then the gas gets released kind of in an uncontrolled fashion?

A Natural gas being lighter than air, it would go up, yes.

Q And when we say "natural gas," we're talking about gas that's 85 percent methane; is that correct?

A Well, not necessarily. Every natural gas has a different composition. It could be 85 percent methane. It could be more or less.

Q The gas that is used in power plants is 85 percent methane; is that right?

A Generally, yes, or more.

Q Methane is a greenhouse gas; is that correct?

A It is a greenhouse gas. It's the simplest hydrocarbon.

Q What's cratering?

A Cratering could be similar to a sinkhole where you've extracted fluids from underneath near the surface, and the surface collapses.

Q And that could affect production and timing and cause injury?

A Yes.

Q And then there's a reference to explosions. Sometimes explosions happen with natural gas and oil drilling.

A They have happened, although in my experience, I've never experienced any of these things.

Q Are you an operator? Have you spent a lot of time on oil wells?

A I have, yes.

Q But I also read in the resume you were a consultant for a number of years, right?

A Yes.

Q How many years did you spend on oil wells or natural gas wells?

A During various parts of my career, I worked in field operations, so really 20 percent of my career.

Q And then you were doing operations when you were there?

A Yes, in the field doing operations; on the rigs directing operations.

Q Down on operational hazards, they also identified pollution and other environmental risks. Can you tell us what pollution and other environmental risks are associated with drilling an oil and natural gas well?

A Well, if you have the circumstances you describe earlier where there's a blowout of oil and the oil got on the surface of the ground, then that would be pollution. If it got into a fresh water drinking source, that would be pollution.

Q So, right now, this project is not on schedule. I think we've established that with other witnesses, correct?

A That's correct. The drilling did not start on schedule, but it is on going now.

Q And part of the reason it didn't start on time is the company, this PetroQuest company, can only find one rig to drill; is that right?

A They found one rig that was suitable for operation in this project. They are in the process of adding another.

Q If you're in the oil and natural gas drilling business, I would assume you would be able to access a drilling well. Am I just not understanding it?

A No, I think you're absolutely right. There are probably a number of drilling rigs out there available, but we want to get the right rig for the job that's being done. We don't want to get some rig that's not suitable for the job being done.

Q So, is it your testimony that each rig is unique, kind of like a fingerprint?

A There are certain types of rigs that that class of rig is unique from other classes of rigs.

Q How many classes of rigs?

A I don't know. Many.

Q So, they are not all unique. It's not like a fingerprint, right?

A No, you wouldn't want to drill a horizontal well that has a 5000-foot lateral section with a well that's only capable of drilling 5000 feet vertically.

Q So, let me flip you to Page 24 of this exhibit down towards the bottom. Would you please read the last bold section into the record.

A "Federal and state legislation and regulatory initiatives relating to oil and natural gas development and hydraulic fracturing could result in increased costs and additional operating restrictions or delays."

Q So, the popular press uses the term "fracking." Is that the same as hydraulic fracturing?

A Generally, yes.

Q And the first sentence following that says that this process involves "the injection of water, sand chemicals under pressure in the rock formations to enhance oil and natural gas production."

Is that your understanding?

A Yes.

Q When they say "hydraulic," what does hydraulic reference?

A Water. Hydra.

Q And when they say that chemicals are used, you're an expert in this. Give me one chemical that's used.

A I'm not an expert in hydraulic fracturing composition of the fluids, but generally they are predominantly water and some other chemical is used for stabilizing agents.

Q Can you give me an example of what one might be?

A No, I cannot.

Q And up on the top of this Page 24, there's a reference to the explosion and the sinking of the Deep Water Horizon drilling rig and the resulting oil spill may significantly increase risks, costs and delays. You don't disagree with that statement, do you?

A I don't disagree that there was a problem with the Deep Water Horizon in the Gulf of Mexico, a very different environment than the Woodford Shale. Much higher pressure and a very different circumstance.

Q And specifically with respect to that, the company is saying it could increase their risks and their costs and delays. You don't have any reason to disagree with that statement?

A It certainly increased their costs, yes.

Q What's the worst accident that you're familiar with with respect to an oil and gas drilling operation on land? The Deep Water Horizon was at sea, right?

A Yes.

Q What's the worst accident that you're familiar with with respect to a drilling operation that took place on land?

A I can't remember a specific example. I've never been involved with one myself.

Q With respect to your involvement in the industry, can you --

A Well, of course, I've heard reports in the industry of people getting injured on drilling rigs and even, in some cases, death.

Q And did you do due diligence on PetroQuest,

figure out what kind of company they were?

A Yes.

Q Did you look at their financials or look at how Moody's rated them?

A No.

Q You didn't look at any of their financials?

A No, it was irrelevant to what I did.

Q Do you know if anybody looked at their financials?

A No.

Q All right. I don't want to belabor this, but there's a number of portions of this document that talk about cash flow issues and liquidity. It will speak for itself. You don't have any reason to disbelieve anything that's set forth in this exhibit, correct?

A I have no knowledge of what's in that exhibit at all. I haven't read it.

Q But my question was: You have no reason to doubt anything in here. It's an SEC filing, right? Those are typically true.

A That's true, but as you and I have discussed before, many of these risks that they've identified are boilerplate risks that everybody that's in the oil industry that's a publicly-traded company is going to put in their annual report.

Q Right. And I think we talked about it before. It's because there are real and actual risks that may -- not necessarily will but they could happen.

A I wouldn't characterize them as real and actual risk. I would characterize them as potential risk.

Q So, you also spent time and you looked at a lot of information with respect to the project in question that was provided to you by PetroQuest, correct?

A Yes.

Q Are you aware that PetroQuest in their contractual documents told USG that they shouldn't rely on any of the data that was provided by PetroQuest or words to that effect?

A No, I'm not aware of that.

Q If you were aware of that, would that change your view?

A I would still rely on the data that I had in front of me to do the analysis that I did.

Q But maybe less so?

A No, I mean, the data that I get is actual data. I'll use that data to the purpose that it's intended. Can I give you an example?

Q I was going to ask you. If I told you to go

to the University of Florida, what you need to do is you need to go out to I-10 and go west, and say don't rely on my data but go ahead and go west on I-10, that probably wouldn't work out very well for you since you got to go east to get to Gainesville.

A I'll take your word for that.

Q And with respect to representation of warranties, if a company's affirmatively stating that you should not rely on any of their information, that doesn't cause any concern for you?

A Without knowing what the context of that comment was, no.

Q Would it help you if I showed it to you?

A Sure.

MR. MOYLE: Give me a minute, Mr. Chairman.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: It's in a confidential document.

BY MR. MOYLE:

Q So the record is clear, I'm showing you Sam Forrest, No. 4, Page 65 of 78 and Page 66. There are some highlights there. And I've starred -- you see a star down there at the bottom of Page 65?

A Yes.

Q If you would just read into the record starting with the sentence following the star until you

get to the star on Page 66.

MR. YOUNG: Mr. Chairman, I think Mr. Moyle just said this is confidential information.

MR. MOYLE: And then I also think in redacted version of Mr. Forrest's deposition --

THE WITNESS: I think it was unredacted. I'll defer to Mr. Butler.

MR. BUTLER: I'd like to see the reference in the deposition you are referring to to confirm that it's, in fact, not confidential. Do you have a page reference, Mr. Moyle?

MR. MOYLE: No, I read it this morning. I don't have it, Mr. Butler, but I think -- I'll represent to you that the portion about the -- I'll look for it.

MR. BUTLER: I'm wondering whether it would be faster for us to take a very short break for me to confer with the witness and Mr. Forrest and see whether we can confirm that this part is okay to do non-confidentially.

CHAIRMAN GRAHAM: Sounds like a good time to -- the clock behind me says about two after. Let's go up to ten after. Seven or eight minutes.

(Brief recess.)

C E R T I F I C A T E

STATE OF FLORIDA)
COUNTY OF LEON)

I, LISA GAINEY, Court Reporter and Notary Public at Tallahassee, Florida, do hereby certify as follows:

THAT I correctly reported in shorthand the foregoing proceedings, at the time and place as stated in the caption hereof;

THAT I later reduced my stenographic notes through computer-aided transcription, or under my supervision, to typewritten copy, and that the foregoing pages, numbered 1 through , both inclusive, contain a full, true, and correct transcript of the proceedings on said occasion;

THAT I am neither of kin nor of counsel to any of the parties involved in this matter, nor in any manner interested in the results thereof;

THIS 2nd day of December, 2014.

Lisa Gainey

____
LISA GAINEY
Notary Public
Commission: #EE198942
Expires May 23, 2016

EXHIBIT NO. ___

DOCKET NO: 140001-EI

WITNESS: Deason & Ousdahl

PARTY: Florida Power & Light Company

DESCRIPTION: Order No. PSC-13-0023-S-EI (Excerpt)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 120015-EI ORDER NO. PSC-13-0023-S-EI ISSUED: January 14, 2013

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

ORDER APPROVING REVISED STIPULATION AND SETTLEMENT

BY THE COMMISSION:

Background

On March 19, 2012, pursuant to Section 366.06, Florida Statutes (F.S.), and Rules 25-6.0425 and 25-6.043, Florida Administrative Code (F.A.C.), Florida Power & Light Company (FPL) filed a petition for approval of permanent increase of its base rates and charges. In its petition, FPL requested a base rate increase of $528 million with a Return on Equity (ROE) of 11.25%, plus a .25% performance adder to remain as long as it maintained the lowest electrical rates in the state compared to the other 4 Investor Owned Utilities. Twelve parties were granted intervention in the docket.[1] However, several parties were dismissed from the docket for various reasons.[2] By the Order Establishing Procedure, Order No. PSC-12-0143-PCO-EI, issued March 26, 2012, the hearing was set to commence on August 20, 2012. In May, June and August, 2012, nine Commission service hearings were held throughout FPL's service territory. On August 15, 2012, FPL and three of the eleven intervening parties filed a Motion to Approve Settlement

[1] Office of Public Counsel (OPC), South Florida Hospital and Healthcare Association (SFHHA), Florida Retail Federation (FRF), Thomas Saporito (Saporito), Florida Industrial Power Users Group (FIPUG), Village of Pinecrest, Federal Executive Agencies (FEA), Glen Gibellina, Larry Nelson, John Hendricks, Algenol Biofuels Inc., and Daniel and Alexandria Larson.

[2] Mr. and Mrs. Larson and Mr. Nelson were dismissed as parties from the docket and their positions on the issues were stricken pursuant to Section VII(a) of Order No. PSC-12-0143-PCO-EI, the Order Establishing Procedure. Section VII(a) provides "[U]nless excused by the Presiding Officer for good cause shown, each party (or designated representative) shall personally appear at the hearing. Failure of a party, or that party's representative, to appear shall constitute waiver of that party's issues, and that party may be dismissed from the proceeding." Both Mrs. Larson and Mr. Nelson subsequently filed Petitions to Re-intervene and Intervene respectively in the supplemental portion of the hearing, and those petitions were denied. Mr. Gibellina was dismissed from the docket for failure to appear at the Prehearing Conference.

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Agreement (Settlement Agreement) and a Motion to Suspend the Procedural Schedule.[3] The Motion to Suspend the Procedural Schedule was denied by Order No. PSC-12-0430-PCO-EI, issued August 17, 2012. The technical hearing commenced on August 20, 2012, and lasted 10 days.

On August 27, 2012, Order No. PSC-12-0440-PCO-EI, the Second Order Revising Order Establishing Procedure (Second Order) was issued establishing a procedural schedule for further actions necessary for us to consider the proposed Settlement Agreement. The Second Order stated that upon conclusion of the evidentiary portion of the hearing, a date and time would be set for the sole purpose of taking up the proposed Settlement Agreement. Also, the Second Order gave all parties an opportunity to conduct informal discovery on the proposed Settlement Agreement. On August 31, 2012, we announced that the hearing would reconvene on September 27, 2012, and continue on September 28, 2012, if necessary, to consider the proposed Settlement Agreement. On September 27, 2012, we voted to take additional testimony limited to specific issues that were part of the proposed Settlement Agreement, but supplemental to the issues in the rate case. Accordingly, in compliance with Sections 120.569 and 120.57, F.S., the administrative hearing was continued to November 19-20, 2012.

On October 3, 2012, Order No. PSC-12-0529-PCO-EI, the Third Revised Order Establishing Procedure was issued establishing the necessary procedures for discovery and setting dates for filing prefiled testimony, the Prehearing Conference, and supplemental hearing dates. On November 19 and 20, 2012, the supplemental hearing was held, and on November 30 parties filed post-hearing briefs. On December 13, 2012, we convened a Special Agenda Conference to consider the proposed Settlement Agreement filed by FPL, FIPUG, SFHHA, and FEA. At the Special Agenda we expressed our concerns with the proposed Settlement Agreement. We engaged in an extensive discussion of the benefits and detriments associated with the provisions of the proposed Settlement Agreement, and whether the agreement as filed was in the public interest. Upon completion of our discussion, all the parties (signatories and non-signatories) were given an opportunity to engage in further settlement negotiations. Upon reconvening the Special Agenda Conference, the signatories filed a revised Stipulation and Settlement and the non-signatories reiterated their continued objections to our consideration of the proposed or modified agreement.

By this Order, we approve the revised Stipulation and Settlement (Attachment A). We have jurisdiction over these matters pursuant to Chapter 366, F.S., including Sections 366.04, 366.05, 366.06, 366.07, and 366.076, F.S.

<u>The August 15, 2012 Proposed Settlement Agreement</u>

The major elements of the August 15, 2012 proposed agreement included the following:

[3] FPL, FIPUG, FEA, and SFHHA are the signatories to the Settlement Agreement. While Algenol did not execute the Settlement Agreement or join in the motion, it did express its support for the Settlement Agreement. Algenol subsequently withdrew from the proceeding.

- The Term would begin with the first billing cycle of January 2013 and continue through the last billing cycle in December 2016.

- FPL's authorized Return on Equity would be set at 10.70 percent (9.70-11.70 percent range) for all purposes.

- FPL would be authorized to implement a revenue increase of $378 million effective January 1, 2013. The increase would be based on the projected 2013 test year billing determinants contained in FPL's filed Minimum Filing Requirements.

- FPL's proposed minimum late payment charge of $5.00 would be increased to $6.00.

- Demand credits for large commercial and industrial customers in the new CILC and CDR rates would be increased from the credits filed in FPL's MFRs. The increased CILC and CDR credits would be recovered through the energy conservation cost recovery clause (ECCR).

- FPL would not be precluded from petitioning the Commission to seek recovery of costs associated with any storms. Storm cost recovery would begin, on an interim basis, 60 days from the filing of a storm cost recovery petition and associated tariff. Storm cost recovery charges would be assessed over a 12-month period if the costs do not exceed $4.00/1,000 kWh on a monthly residential customer bill. Storm cost recovery in excess of $4.00/1,000 kWh would be recovered in a subsequent year or years as determined by the Commission.

- FPL would continue to recover the annual non-fuel revenue requirements for West County Unit 3 through the capacity cost recovery clause in the same manner provided in the 2010 Rate Case Settlement, except that upon the implementation date of the proposed settlement, recovery would no longer be limited to the projected fuel cost savings.

- The revenue requirements associated with West County Unit 3 would be allocated to customer classes based on the cost of service and rate design methodology reflected in FPL's filed MFRS in the current case. Recovery of West County Unit 3's revenue requirements would survive termination of the proposed settlement and would continue until such time as new base rates are authorized for FPL.

- FPL would be allowed three generation base rate increases (GBRA): June 2013 – Canaveral; June 2014 – Riviera; and June 2016 – Port Everglades. FPL would file for each GBRA through the Capacity clause. Each GBRA would be calculated using a 10.70 percent ROE and the capital structure reflected in FPL's MFRs for the Canaveral Step Increase. The proposed settlement provides for a true up to actual capital expenditures if capital costs are lower than projected. FPL would provide any refund through the Capacity Clause and base rates would be adjusted going forward. FPL would be required to initiate a limited proceeding if it chooses to pursue a revenue increase for higher capital costs. For the Canaveral Modernization Project, the revenue requirement would be based on FPL's current rate petition and MFRs. The Riviera and Port Everglades revenue requirements would be based on the cumulative present value of revenue requirements reflected in the respective need determinations. Each GBRA would be reflected in FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously.

- If FPL's achieved ROE falls below 9.70 percent during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, FPL could petition the Commission to amend its base rates and may seek interim relief. If FPL's achieved ROE exceeds 11.70 percent during the settlement term on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, any other Party could petition the Commission to amend its base rates and may seek interim relief. This Agreement would terminate upon the effective date of any final order issued in any rate relief proceeding.

- FPL would amortize its projected depreciation reserve surplus and a portion of its fossil dismantlement reserve (termed the "Reserve Amount") over the period of the Agreement, not to exceed $400 million.

- No depreciation or dismantlement studies would be required to be filed during the Term of the Agreement.

- An Incentive Mechanism would become effective on the implementation date of the Settlement. The Incentive Mechanism involves the sharing of gains resulting from electric wholesale purchases and sales, and asset optimization. Asset optimization involves: gas storage utilization; city-gate gas sales using existing transport; production area gas sales; capacity release of gas transport and electric transmission; and the outsourcing of the optimization function. Annually, as part of the fuel cost recovery clause, FPL would file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. FPL customers would receive 100 percent of the gain from electric wholesale sales and purchases and asset optimization up to a threshold of $36 million ("Customer Savings Threshold.") FPL customers would also receive 100 percent of the gain for the first $10 million above the Customer Savings Threshold (termed "Additional Customer Savings"). Incremental gains above the Customer Savings Threshold and the Additional Customers Savings (totaling $46 million) would be shared between FPL and customers as follows:

    1. Between $46 million and $75 million, customers receive 30 percent of the incremental gains;
    2. Between $75 and $100 million, customers receive 40 percent of the incremental gains.

3. Over $100 million, customers receive 50 percent of the incremental gains.

The customers' portion of all gains would be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL would be entitled to recover through the Fuel Clause reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs and asset optimization measures. Such costs include: incremental personnel costs, software and associated hardware costs. In addition, variable power plant O&M costs incurred to generate additional output in order to make wholesale sales, if the level of sales exceeds 514,000 MWh.

Decision

At the Special Agenda Conference, we expressed our concerns with the proposed Settlement Agreement. We engaged in an extensive discussion of the benefits and detriments associated with provisions of the proposed Settlement Agreement, and whether the agreement as filed was in the public interest. Upon completion of our discussion, all parties were given an opportunity to engage in further settlement negotiations. Upon reconvening the Special Agenda Conference, the signatories filed a revised Stipulation and Settlement and the non-signatories reiterated their continued objections to our consideration of the proposed and modified agreements. The modified agreement incorporates changes based upon our extensive discussion. The changes are discussed below.

- FPL's authorized Return on Equity was reduced to 10.50 percent from 10.70 percent for all purposes.

- The revenue increase was reduced from $378 million to $350 million effective January 1, 2013. The increase is based on the projected 2013 test year billing determinants contained in FPL's filed Minimum Filing Requirements. We note that $18 million of the reduction in the requested revenue shall be allocated directly to the base customer and energy charges for the residential rate class only.

- FPL's minimum late payment charge was reduced from $6.00 to $5.00 as originally requested in FPL's MFRs.

- FPL shall be allowed three generation base rate increases (GBRA): June 2013 – Canaveral, June 2014 – Riviera, and June 2016 – Port Everglades. FPL will file for each GBRA through the Capacity clause. Each GBRA will be calculated using a 10.50 percent ROE, instead of 10.70 as originally proposed, and using the capital structure reflected in FPL's MFRs for the Canaveral Step Increase. The settlement provides for a true up to actual capital expenditures if capital costs are lower than projected. FPL will provide any refund through the Capacity Clause and base rates will be adjusted going forward. It will be FPL's obligation to initiate a limited proceeding if it chooses to pursue a revenue increase for higher capital costs. For the Canaveral Modernization Project, the revenue requirement will be based on FPL's current rate petition and MFRs. The Riviera and Port Everglades revenue requirements will be based on the cumulative present value of revenue requirement reflected in the respective need determinations. Each GBRA will be reflected in FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously. FPL shall calculate and submit for our staff's administrative approval the amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that each modernization plant is to go into service. These filing shall include revised tariff sheets for the year that each modernization plant is to go into commercial service.

- If FPL's achieved ROE falls below 9.50 percent, instead of 9.70 percent as originally proposed, during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the Commission to amend its base rates and may seek interim relief. If FPL's achieved ROE exceeds 11.50 percent during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, any other Party may petition the Commission to amend its base rates and may seek interim relief. This Agreement terminates upon the effective date of any final order issued in any rate relief proceeding.

- An Incentive Mechanism will become effective on the implementation date of the revised Stipulation and Settlement. This is a four-year pilot program. The Commission has the option to review this pilot program after two years. Upon review, if the Commission determines that the pilot program is not providing the kinds of benefits that it anticipated or if the Commission determines the pilot program is not satisfactory, the Commission may terminate this pilot program. The Incentive Mechanism involves the sharing of gains resulting from electric wholesale purchases and sales, and asset optimization. Asset optimization involves: gas storage utilization; city-gate gas sales using existing transport; production area gas sales; capacity release of gas transport and electric transmission; and the outsourcing of the optimization function. Annually, as part of the fuel cost recovery clause, FPL will file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. FPL customers will receive 100 percent of the gain from electric wholesale sales and purchases and asset optimization up to a threshold of $36 million ("Customer Savings Threshold"). FPL customers will also receive 100 percent of the gain for the first $10 million above the Customer Savings Threshold (termed "Additional Customer Savings"). Incremental gains above the Customer Savings Threshold and the Additional Customers Savings (totaling $46 million) will be shared between FPL and customers as follows:

1. Between $46 million and $100 million, customers receive 40 percent of the incremental gains.
2. Over $100 million, customers receive 50 percent of the incremental gains.

The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL will be entitled to recover through the Fuel Clause reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs and asset optimization measures. Such costs include: incremental personnel costs, software, and associated hardware costs. In addition, variable power plant O&M costs incurred to generate additional output in order to make wholesale sales will be included if the level of sales exceeds 514,000 MWh.

We note that with respect to the GBRA, we find that it is the public interest because it provides a benefit to both FPL's customers and FPL. We already approved the need for the Canaveral, Riviera, and Port Everglades Modernization Projects when we considered FPL's need determination petitions. The GBRA provides the mechanism for FPL to recover the costs to modernize these plants and bring them into commercial service. We also find that the pilot incentive mechanism is in the public interest. The pilot incentive mechanism is beneficial to both FPL's customers and FPL. We note that this is a four-year pilot program and we have the option to review it after two years. If we determine that the program is not providing the kinds of benefits that are anticipated, or if we determine the pilot program is otherwise unsatisfactory, we may terminate the program.

Settlement agreements are approved if we determine that they are in the public interest.[4] The public interest standard that we apply in approving the revised Stipulation and Settlement requires a fact-intensive, case-specific analysis. Having carefully reviewed the evidence in the record, and having discussed the benefits and detriments associated with the revised Stipulation and Settlement, we find that as a whole the settlement is in the public interest. It provides a reasonable resolution of all the issues in this proceeding regarding FPL's rates and charges. It also provides FPL's customers with stability and predictability with respect to their electricity rates, while allowing FPL to maintain the financial strength to make investments necessary to

[4] Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

provide customers with safe and reliable power. All stipulated issues that were approved in this docket on August 31, 2012, are superseded by our approval of the revised Stipulation and Settlement.

We find, therefore, consistent with our ongoing authority and obligation, that the revised Stipulation and Settlement establishes rates that are fair, just, and reasonable in the public interest. We have a long history of encouraging settlements that are in the public interest, and we believe it is appropriate to do so in this case as well.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the revised Stipulation and Settlement filed December 13, 2013, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that FPL shall file for our staff's administrative approval revised tariff sheets to reflect the terms of the revised Stipulation and Settlement. It is further

ORDERED that FPL shall calculate and submit for our staff's administrative approval the amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that each modernization plant is to go into commercial service. These filing shall include revised tariff sheets for the year that each modernization plant is to go into commercial service. It is further

ORDERED that Docket No. 120015-EI shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of January, 2013.

Ann Cole

ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

KY

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.)	Docket No. 120015-EI

STIPULATION AND SETTLEMENT

WHEREAS, Florida Power & Light Company ("FPL" or the "Company"), the Florida Industrial Power Users Group ("FIPUG"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Federal Executive Agencies ("FEA") have signed this Stipulation and Settlement (the "Agreement"; unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement); and

WHEREAS, on February 1, 2011, the Florida Public Service Commission ("FPSC" or "Commission") entered Order No. PSC-11-0089-S-EI approving a stipulation and settlement of FPL's rate case in Docket Nos. 080677-EI and 090130-EI, which continues in effect through the last billing cycle in December 2012 (the "2010 Rate Case Stipulation"); and

WHEREAS, on March 19, 2012, FPL petitioned the Commission for an increase in base rates of approximately $516.5 million to be effective on January 1, 2013 following the expiration of the 2010 Rate Case Stipulation, for a step increase of $173.9 million to be effective upon the commercial in-service date of the Canaveral Modernization Project (scheduled to be June 1, 2013), and for other related relief (the "2012 Rate Petition"); and

WHEREAS, the Parties have filed voluminous prepared testimony with accompanying exhibits and conducted extensive discovery; and

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WHEREAS, the Parties recognize that this is a period of substantial economic uncertainty, in which economic development and job creation are vitally important to the state of Florida; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability and predictability with respect to FPL's base rates and charges, as well as to promote economic development, job creation and stability;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement will become effective on the first billing cycle of January 2013 (the "Implementation Date") and continue through the last billing cycle in December 2016 (the period from the Implementation Date through the last billing cycle in December 2016 may be referred to herein as the "Term").

2. FPL's authorized rate of return on common equity ("ROE") shall be a range of 9.50% to 11.50%, with a mid-point of 10.50%. FPL's authorized ROE range and mid-point shall be used for all purposes during the Term.

3. (a) Upon the Implementation Date and effective with the first billing cycle in January 2013, FPL shall increase its base rates and service charges by an amount that is intended to generate an additional $350 million of annual revenues, based on the projected 2013 test year billing determinants reflected in the Minimum Filing Requirements ("MFRs")

filed with the 2012 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(b) Attached hereto as Exhibit B are tariff sheets for new base rates and service charges that implement the $350 million rate increase described in Paragraph (3)(a) above, which tariff sheets shall become effective on the first billing cycle of January 2013. The new base rates reflected in the attached tariff sheets are based on the billing determinants, cost of service allocations and rate design in the MFRs accompanying the 2012 Rate Petition and include additional adjustments, all of which are reflected in Exhibit A; provided, however, that: (i) the allocation of revenue responsibility for the base customer and energy charges for the residential rate class (i.e., RS(T)-1) shall be reduced by an additional $18 million; (ii) the minimum late payment charge shall be $5.00; and (iii) consistent with FPL's recently approved revised Economic Development Rider and to promote further economic development and job creation, (A) the energy and demand charges for business and commercial rates are adjusted as shown in Exhibit B, and (B) the utility-controlled demand credits for large commercial and industrial customers in the new CILC and CDR rates are greater than the credits reflected in such MFRs, and the relationship between the non-fuel energy and demand charges in the CILC rates are revised. FPL shall be entitled to recover the increased CILC and CDR credits through the energy conservation cost recovery ("ECCR") clause.

(c) Base rates set in accordance with this Paragraph 3 shall not be changed during the Term except as otherwise permitted in this Agreement.

4. Nothing in this Agreement shall preclude FPL from requesting the Commission to approve the recovery of costs that are recoverable through base rates under the nuclear cost recovery statute, Section 366.93, Florida Statutes, and Commission Rule 25-6.0423, F.A.C. Parties may participate in nuclear cost recovery proceedings and proceedings related thereto and may oppose FPL's requests.

5. (a) Nothing in this Agreement shall preclude FPL from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or level of theoretical depreciation reserve. Consistent with the rate design method set forth in Order No. PSC-06-0464-FOF-EI, the Parties agree that recovery of storm costs from customers will begin, on an interim basis, sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission. All storm related costs subject to interim recovery under this Paragraph 5 shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, to the estimate of incremental costs above the level of storm reserve prior to the storm and to the replenishment of the storm reserve to the level as of the Implementation Date. The Parties to this Agreement are not precluded from participating in any such proceedings and opposing the amount of FPL's claimed

costs but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 will apply in aggregate for a calendar year; provided, however, that FPL may petition the Commission to allow FPL to increase the initial 12 month recovery beyond $4.00/1,000 kWh in the event FPL incurs in excess of $800 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to the level that existed as of the Implementation Date. All Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of theoretical depreciation reserve.

6. Nothing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically, and ordinarily would be

recovered through base rates. It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or atypical kinds of costs (including but not limited to, for example, requirements related to cybersecurity or the requirements for seismic and flood protection at nuclear plants arising out of the Fukushima Daiichi event), and concurrently or in connection with the imposition of such requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause. Nothing in this Agreement shall affect the shifts from clause to base rate recovery and from base rate to clause recovery that were set forth in the 2012 Rate Petition and accompanying MFRs.

7. (a) FPL will continue throughout the Term to recover the annual non-fuel revenue requirements for West County Unit 3 via its capacity cost recovery clause (the "Capacity Clause") in the manner provided in the 2010 Rate Case Stipulation; provided, however, that commencing upon the Implementation Date, such recovery shall not be limited to the projected fuel cost savings for West County Unit 3.

(b) The revenue requirements associated with West County Unit 3 quantified pursuant to this paragraph shall be allocated to customer classes utilizing the same cost of service and rate design methodology reflected in the MFRs accompanying the 2012 Rate Petition.

(c) FPL's right to recover the non-fuel revenue requirements for West County Unit 3 pursuant to this Paragraph 7 shall survive termination of this Agreement and shall continue until such time as new base rates are authorized for FPL that are based on a test year that reflects the then applicable non-fuel revenue requirements for West County Unit 3.

8. (a) FPL projects that the following three power plant modernization projects will enter commercial service while this Agreement is in effect: the Canaveral Modernization Project (projected to go into service June 2013), the Riviera Modernization Project (projected to go into service June 2014), and the Port Everglades Modernization Project (projected to go in service June 2016). For each of these three modernization projects, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). For the Canaveral Modernization Project, the Annualized Base Revenue Requirement shall be as reflected in the 2012 Rate Petition and accompanying MFRs; for the Riviera and Port Everglades Modernization Projects, the Annualized Base Revenue Requirement shall reflect the costs upon which the cumulative present value of revenue requirements was predicated, and pursuant to which a need determination was granted by the Commission. Each such base rate adjustment will be referred to as a Generation Base Rate Adjustment ("GBRA").

(b) Each GBRA is to be reflected on FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity (excluding West County Unit 3 revenues) during the first twelve months of operation.

FPL will begin applying the incremental base rate charges and base credits for each of the three modernization projects to meter readings made on and after the commercial in-service date of that modernization project.

(c) Each GBRA will be calculated using a 10.50% ROE and the capital structure reflected in the Canaveral Step Increase MFRs accompanying the 2012 Rate Petition. FPL will calculate and submit for Commission confirmation that amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that modernization project is to go into service.

(d) In the event that the actual capital expenditures are less than the projected costs used to develop the initial GBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the Capacity Clause. In order to determine the amount of this credit, a revised GBRA Factor will be computed using the same data and methodology incorporated in the initial GBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going forward basis, base rates will be adjusted to reflect the revised GBRA factor. The difference between the cumulative base revenues since the implementation of the initial GBRA factor and the cumulative base revenues that would have resulted if the revised GBRA factor had been in-place during the same time period will be credited to customers through the Capacity Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(e) In the event that actual capital costs for a modernization project are higher than the projection on which the Annualized Base Revenue Requirement was based, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall increase the GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Any Party may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15).

(f) Upon expiration or termination of this Agreement, FPL's base rate levels, including the effects of the GBRAs as implemented in this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues) for each of the modernization projects that achieved commercial in-service operation during the term of this Agreement, shall continue in effect until next reset by the Commission.

9. (a) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity falls below 9.50% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the FPSC to amend its base rates, either as a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, and/or as a limited proceeding under Section 366.076, Florida Statutes. (Throughout this Agreement, "FPSC actual, adjusted basis" and "actual adjusted earned return" shall mean

results reflecting all adjustments to FPL's books required by the Commission by rule or order, but excluding pro forma, weather-related adjustments.) If FPL files a petition to initiate a general rate proceeding pursuant to this provision, FPL may request an interim rate increase pursuant to the provisions of Section 366.071, Florida Statutes. The other Parties to this Agreement shall be entitled to participate in any proceeding initiated by FPL to increase base rates pursuant to this paragraph, and may oppose FPL's request.

(b) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity exceeds 11.50% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, any other Party shall be entitled to petition the Commission for a review of FPL's base rates. In any case initiated by FPL or any other Party pursuant to this paragraph, all parties will have full rights conferred by law.

(c) Notwithstanding Paragraph 3 above, this Agreement shall terminate upon the effective date of any final order issued in any such proceeding pursuant to this Paragraph 9 that changes FPL's base rates prior to the last billing cycle of December 2016.

(d) This Paragraph 9 shall not (i) be construed to bar or limit FPL to any recovery of costs otherwise contemplated by this Agreement; (ii) apply to any request to change FPL's base rates that would become effective after this Agreement terminates; or (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the termination of this Agreement to argue that FPL's authorized ROE range should be different than 9.50% to 11.50%.

10. (a) In Order No. PSC-10-0153-FOF-EI, the Commission determined a net theoretical depreciation reserve surplus in the total amount of $894 million (the "Total Depreciation

Reserve Surplus"). The Commission directed FPL to amortize the Total Depreciation Reserve Surplus over four years, ending in 2013. Pursuant to the 2010 Rate Case Stipulation, the Parties therein agreed that in each year during the term of that agreement, FPL would have discretion to vary the amount of amortization of Total Depreciation Reserve Surplus taken in that year, subject to certain limitations. As a result of FPL's actual and projected discretionary amortization during 2010-2012, the 2012 Rate Petition and accompanying MFRs projected that FPL would have $191 million of Total Depreciation Reserve Surplus remaining at the end of 2012 and would amortize that amount in 2013. The actual remaining amount may differ from the projected amount of $191 million.

(b) Notwithstanding Order No. PSC-10-0153-FOF-EI or the 2010 Rate Case Stipulation, the Parties agree that over the Term of this Agreement, FPL may amortize the Total Depreciation Reserve Surplus remaining at the end of 2012, plus a portion of FPL's Fossil Dismantlement Reserve (together the "Reserve Amount") with the amounts to be amortized in each year of the Term left to FPL's discretion subject to the following conditions: (i) the amount of Total Depreciation Reserve Surplus that FPL may amortize during the term shall not be less than $191 million (or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012) and the total Reserve Amount amortized during the Term shall not exceed $400 million[1] subject to (iii) below; (ii) for any surveillance reports submitted by FPL during the Term on which its return on equity (measured on an FPSC actual, adjusted basis) would otherwise fall below 9.50%,

[1] The Company would record the $191 million of net surplus amortization or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012, to the cost of removal component of the depreciation reserve to ensure that the amount of net surplus amortization on the financial statements equals the amount of net surplus amortization reflected in rates.

FPL must amortize at least the amount of the available Reserve Amount necessary to maintain in each such 12-month period a return on equity of 9.50% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize Reserve Amount in an amount that results in FPL achieving a return on equity of greater than 11.50% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL during the Term. FPL shall not satisfy the requirement of Paragraph 9 that its actual adjusted earned return on equity must fall below 9.50% on a monthly surveillance report before it may initiate a petition to increase base rates during the Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned return on equity to at least 9.50% for the period in question.

11. Notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., FPL shall not be required during the Term to file any depreciation study or dismantlement study. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect throughout the Term. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364 pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL during the Term.

12. (a) In order to create additional value for customers by FPL engaging in both wholesale power purchases and sales, as well as all forms of asset optimization, the Parties agree that FPL will be subject to the following mechanism, effective on the Implementation Date (the "Incentive Mechanism"):

(i) FPL will file each year as part of its fuel cost recovery clause ("Fuel Clause") final true-up filing a schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization that it undertook in that year (the "Total Gains Schedule").[2] FPL's final true-up filing will include a description of each asset optimization measure for which gain is included on the Total Gains Schedule for the prior year, and such measures shall be subject to review by the Commission to determine that they are eligible for inclusion in the Incentive Mechanism.

(ii) For the purposes of the Incentive Mechanism, "asset optimization" includes but is not limited to:

- Gas storage utilization (FPL could release contracted storage space or sell stored gas during non-critical demand seasons);
- Delivered city-gate gas sales using existing transport (FPL could sell gas to Florida customers, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);
- Production (upstream) area sales (FPL could sell gas in the gas-production areas, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);

[2] For the purpose of this Agreement, "short-term" is intended to refer to non-separated wholesale sales and purchases. Order No. PSC-97-0262-FOF-EI defined "non-separated" sales as "sales that are non-firm or less than one year in duration."

- Capacity Release of gas transport and electric transmission (FPL could sell idle gas transportation and/or electric transmission capacity for short periods when it is not needed to serve FPL's native load;
- Asset Management Agreement ("AMA") (FPL could outsource optimization function such as those described above to a third party through assignment of transportation and/or storage rights in exchange for a premium to be paid to FPL).

(ii) On an annual basis, FPL customers will receive 100% of the gain described in Paragraph 12(a)(i), up to a threshold of $36 million ("Customer Savings Threshold"). In addition, FPL customers will receive 100% of the gain described in Paragraph 12(a)(i) for the first $10 million above the Customer Savings Threshold ("Additional Customer Savings"). Incremental gains above the total of the Customer Savings Threshold and the Additional Customer Savings (i.e., above a gain of $46 million) will be shared between FPL and customers as follows: FPL will retain 60% and customers will receive 40% of incremental gains between $46 million and $100 million; and FPL will retain 50% and customers will receive 50% of all incremental gains in excess of $100 million. The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL agrees that it will not require any native load customer to be interrupted in order to initiate or maintain an economy sale, whether that sale is firm or non-firm.

(b) FPL will be entitled to recover through the Fuel Clause the following types of reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs as well as the asset optimization measures (the "Incremental Optimization Costs"):

(i) incremental personnel, software and associated hardware costs incurred by FPL to manage the expanded short-term wholesale purchases and sales programs and the asset optimization measures; and

(ii) variable power plant O&M costs[3] incurred by FPL to generate additional output in order to make wholesale sales, to the extent that the level of such sales exceed 514,000 MWh (*i.e.*, the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), with such costs determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs.

FPL's final true-up filing will separately state and describe the Incremental Optimization Costs that it incurred in the prior year, and such costs shall be subject to review and approval by the Commission.

(c) On or after January 2, 2015 (*i.e.*, two years after the Implementation Date), the Commission may review and, if continuing the Incentive Mechanism is deemed not to be in the public interest, terminate the Incentive Mechanism for the remainder of the Term.

13. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 9, a Party to this Agreement will neither seek nor support any reduction in FPL's base rates, including limited, interim or any other rate decreases, that would take effect prior to the first billing

[3] For the purpose of this Agreement, "variable power plant O&M costs" includes non-fuel O&M expenses and costs for capital replacement parts that vary as a function of a power plant's output.

cycle for January 2017, except for any such reduction requested by FPL or as otherwise provided for in this Agreement. FPL shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraph 9 of this Agreement. FPL is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2017, nor are the Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2017, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this Agreement.

14. Nothing in this Agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the Term unless the application of such new or revised tariff or rate schedule is optional to FPL's customers.

15. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof; provided, however, that nothing in this Agreement shall affect FIPUG's right to continue its appeal of Order No. PSC-12-0187-FOF-EI granting an affirmative determination of need for the Port

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Everglades Modernization Project or FPL's right to oppose that appeal. No party will assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value. Approval of this Agreement in its entirety will resolve all matters in Docket No. 120015-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes. This docket will be closed effective on the date the Commission Order approving this Agreement is final, and no Party shall seek appellate review of any order issued in these Dockets.

16. This Agreement is dated as of August 15, 2012. It may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party(ies) shall not disturb or diminish the benefits of this Agreement to any current Party.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

By: ______________
Eric E. Silagy

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Notice of Filing Signature Page to revised FPL Settlement Agreement

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Vicki Gordon Kaufman, Esquire
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The Perkins House
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By: ______________________ 12/13/12
Jon C. Moyle, Jr.

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South Florida Hospital and Healthcare Association
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1350 I Street, N.W., Suite 1100
Washington, DC 20005

By: ______________________
Kenneth L. Wiseman

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Federal Executive Agencies
Lt Col Gregory J. Fike
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403

By: ______________________ 13 Dec 2012
Lt Col Gregory J. Fike

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Q.

Please refer to page 6, paragraph 10, of the petition. For the five-year period 2009 to 2013, provide a table comparing the cost of production from Woodford shale gas reserves to market prices.

A.

FPL was unable to obtain pricing for the Woodford shale for the year 2009. However, according to the global energy research and consulting firm Wood Mackenzie, the break-even price for producers in the Arkoma Basin of the Woodford Arkoma (which is the area of interest for the Woodford Project) is included in the following table:

	2010	2011 1H	2011 2H	2012 1H	2012 2H	2013 1H	2013 2H
Woodford Arkoma (Core)	$ 4.75	$ 4.96	$ 4.40	$ 4.11	$ 3.87	$ 4.04	$ 3.89
NYMEX Henry Hub	$ 4.39	$ 4.21	$ 3.87	$ 2.48	$ 3.10	$ 3.71	$ 3.59

Wood Mackenzie describes the break-even price as the Henry Hub equivalent price at which producers could sell their production while covering all operating costs and earning a 10% rate of return. The table illustrates the central point of Paragraph 10, which is that the cost of production is more stable than the NYMEX market prices. Those market prices were exceptionally low in the 2010-2013 period, but are not projected to remain that low into the future. Rather, they are expected to increase over time and consistently exceed the projected cost of production, which is the point of the last sentence in Paragraph 10 and is illustrated in Exhibit SF-7.