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**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

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| **IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY** | **)<br>)<br>)<br>)<br>)** | **DOCKET NO. 160021-EI** |

**Post-Hearing Brief of Federal Executive Agencies**

**September 19, 2016**

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Federal Executive Agencies ("FEA"), by and through their undersigned counsel, file this Post-Hearing Post-Hearing Brief.

## COST OF COMMON EQUITY

**STATEMENT OF POSTIONS:**

**ISSUE 79: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure**

**A. For the 2017 projected test year?**

**FEA:** Including short-term debt, Mr. Gorman's recommended cost of equity, and recommended embedded cost of debt, the cost rate for investment tax credits should be 7.27%.

**B. If applicable, for the 2018 subsequent projected test year?**

**FEA:** Including short-term debt, Mr. Gorman's recommended cost of equity, and recommended embedded cost of debt, the cost rate for investment tax credits should be 7.27%.

**ISSUE 81: What is the appropriate amount and cost rate for long-term debt to include in the capital structure**

**A. For the 2017 projected test year?**

**FEA:** FPL's projected debt cost of 6.16% new issuances is overstated. FEA witness Gorman recommends an embedded debt cost of 4.51% based on a more reasonable cost of debt for these new issuances.

**B. If applicable, for the 2018 subsequent projected test year?**

**FEA:** FPL's projected debt cost of 6.16% new issuances is overstated. FEA witness Gorman recommends an embedded debt cost of 4.51% based on a more reasonable cost of debt for these new issuances.

**ISSUE 83: What is the appropriate equity ratio to use in the capital structure for ratemaking purposes**

**A. For the 2017 projected test year?**

**<u>FEA</u>:** FPL's capital structure has an excessive amount of common equity and unnecessarily inflates the cost to retail customers. FEA witness Gorman recommends that the Commission should award a return on equity that is lower to reflect this reduction in financial risk.

**B. If applicable, for the 2018 subsequent projected test year?**

**<u>FEA</u>:** FPL's capital structure has an excessive amount of common equity and unnecessarily inflates the cost to retail customers. FEA witness Gorman recommends that the Commission should award a return on equity that is lower to reflect this reduction in financial risk.

**<u>ISSUE 81</u>:** Should FPL's request for a 50 basis point performance adder to the authorized return on equity be approved?

**<u>FEA</u>:** FPL's request for a 50 basis point performance adder is not justified.

**<u>ISSUE 85</u>: What is the appropriate authorized return on equity (ROE) to use in establishing FPL's revenue requirement**

**A. For the 2017 projected test year?**

**<u>FEA</u>:** The appropriate ROE for FPL is 9.25%, which is the midpoint of FEA witness Gorman's recommended range of 8.90% to 9.60%.

**B. If applicable, for the 2018 subsequent projected test year?**

**<u>FEA</u>:** The appropriate ROE for FPL is 9.25%, which is the midpoint of FEA witness Gorman's recommended range of 8.90% to 9.60%.

**<u>ISSUE 82</u>: What is the appropriate weighted average cost of capital to use in establishing FPL's revenue requirement?**

**A. For the 2017 projected test year?**

**<u>FEA</u>:** FPL's ratemaking weighted average cost of capital should be set at 5.56% as recommended by FEA witness Gorman.

**B. If applicable, for the 2018 subsequent projected test year?**

**<u>FEA</u>:** FPL's ratemaking weighted average cost of capital should be set at 5.56% as recommended by FEA witness Gorman.

**DISCUSSION:**

FEA filed testimony on return on equity, embedded cost of debt, and proposed capital structure that will provide Florida Power & Light ("FPL") with an opportunity to realize cash flow financial coverage ratios and balance sheet strength that conservatively supports FPL's current bond rating. The FEA recommendation represents fair compensation for FPL's investment risk and will preserve the Company's financial integrity and credit standing while finding an equitable balance between customers and shareholders, recognizing the reality of the economic hardships of FPL's customers.

The parties made the following recommendations regarding FPL's return on equity (ROE):

**TABLE 1**

**ROE Recommendations**

| Party | Recommendation |
|---|---|
| OPC | 8.75% |
| FEA | 9.25% |
| SFHHA | 9.00% |
| FPL | 11.50%[1] |

The recommendations of intervenors reflect current market conditions under which utilities, including FPL, have strong and improving credit ratings and are able to access capital at low costs. FPL Witness Hevert's recommendation of 11.00%, as well as FPL's requested 11.50% which includes a 50 basis point adder for exceptional service, on the other hand, is unrealistic and inflated. As FEA witness Michael Gorman testified, the principal flaws in FPL witness Robert Hevert's analysis are that (i) his constant growth DCF model uses exaggerated and unsustainable growth estimates, (ii) his multi-stage DCF is based on an inflated, historically derived gross domestic product (GDP) estimate and a flawed accelerated dividend cash flow assumption, (iii)

[1]Dewhurst Direct at 5. Includes Mr. Hevert's recommended ROE of 11.00% plus a 0.50% incentive adder.

his CAPM assumes inflated market risk premiums, and (iv) his bond yield plus risk premium model is based on inflated equity risk premiums.[2] Due to these errors, Mr. Hevert's recommendation significantly overstates FPL's market cost of equity.

**1. Market Conditions.**

In setting ROE, it is important to consider current market conditions. The evidence in this case shows that the market continues to embrace the utility industry as a low-risk investment, that utilities have been able to access large amounts of capital at low cost to fund large capital programs, and that the industry's credit outlook is improving and stable.[3] As part of his return on equity investigation, Mr. Gorman outlined several market factors that clearly demonstrate the market's acceptance of the utility industry as a safe-haven investment. He further noted that utilities have had access to ample low-cost capital to support large capital programs.

Mr. Gorman began his investigation by reviewing current industry valuation metrics based on three different valuation ratios including 1) Price-to-Earnings ("P/E") ratio; 2) Price-to-Cash Flow ("P/CF") ratio; and 3) Price-to-Book ("P/B") ratio. Based on this review, Mr. Gorman concludes that regulated electric utilities have access to equity capital under reasonable terms and conditions, and at a relatively low cost. Mr. Gorman notes that the regulated electric utility industry is experiencing strong and robust valuations.

Next, Mr. Gorman reviewed industry credit rating assessments by Standard & Poor's ("S&P") and Moody's. S&P and Moody's both rate the utility industry as "Stable".[4] Mr. Gorman also observed the industry's current authorized returns on equity, and how they have supported the industry's access to capital to support large capital programs, and how credit rating agencies have

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[2] Gorman Direct at 58.
[3] *Id*. at 7, 11-13.
[4] *Id*.

responded to these regulatory decisions. Mr. Gorman observed that utilities have had access to tremendous amounts of capital at relatively low cost to support very large capital programs. Further, as noted above, the industry average bond rating has increased more recently, and has currently been rated as "Stable." These results have been produced as the industry authorized returns on equity have dropped from over 10%, down to approximately 9.58% to 9.68% in calendar year 2015 through the first two quarters of 2016.[5] Mr. Gorman recognized this as observable market evidence that the current market cost of equity is now in the mid 9.0% area. Mr. Gorman relied on the observable market evidence, in part, in assessing the reasonableness of his return on equity recommendation for FPL in this proceeding.

Mr. Gorman also outlined the relative volatility of electric utility stocks relative to that of the S&P 500. He found that utility stocks have considerably less volatility than the overall market and moved in a more stable and predictable trading range.[6] This stability in stock prices illustrates the low-risk nature of electric utility investments.[7]

FEA's evidence also proves that capital market costs are low for utility companies, which reflects that such companies are perceived as low-risk by market participants. This is illustrated by Mr. Gorman in his Exhibit MPG-15.[8] In this exhibit, Mr. Gorman showed that A-rated, such as FPL, public utility bond yield spreads currently and in 2016 were lower than the spreads over the 36-year average period.[9] This is an indication that public utility bond yields are relatively low in comparison to market bond yields, providing proof that utilities have access to low-cost capital in this market.[10] Access to low-cost capital is also apparent by comparing utility bond yields to

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[5] *Id*. at 6.
[6] *Id*. at 14.
[7] *Id*.
[8] Gorman Direct, Exhibit MPG-15.
[9] *Id*.
[10] Gorman Direct at 44-45.

corporate bond yields. In 2016, Baa utility bond yields traded at a discount to that of Baa corporate bond yields, again showing that utilities' cost of capital is lower than that of Baa rated general corporate issues.[11]

Mr. Gorman's review thus demonstrates that market conditions are favorable for the utility industry generally. The same is true of FPL specifically. FPL's corporate bond ratings from S&P and Moody's are "A-" and "A1," respectively.[12]

**2. The Proxy Group.**

A utility's cost of equity is the return that investors require to invest in the utility. Investors expect to achieve this return through dividends and appreciation in stock price.[13] Because a utility's cost of equity is not directly observable, it is necessary to estimate the proper return through the use of financial models such as the ones utilized by Mr. Gorman in this case. These models, in turn, are applied to a proxy group of publicly traded companies that are similar in total risk profile to FPL.[14] Mr. Gorman's proxy group is based on the same group utilized by Mr. Hevert in his direct testimony, except that Mr. Gorman removed three companies that are involved in merger and acquisitions.[15] Merger and acquisition activities distort the public's view of the stand-alone investment characteristics of the companies involved, making such companies inappropriate for inclusion in a proxy group used to estimate a fair return on equity for a utility.[16] Mr. Hevert also screens companies involved in merger and acquisition activities from his proxy group[17] and, in his rebuttal testimony, he removed the three companies that Mr. Gorman identified.[18]

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[11]*Id*. at Exhibit MPG-15.
[12]Gorman Direct at 15.
[13]*Id*. at 23.
[14]*Id.* at 24.
[15]*Id.* at 25.
[16]*Id.* at 26.
[17]Hevert Direct at 16.
[18]Hevert Rebuttal Exhibit RBH-19.

### 3. Mr. Gorman's recommendation.

Mr. Gorman's recommendation in this case is based on Discounted Cash Flow (DCF) analyses, a Risk Premium analysis, and a Capital Asset Pricing Model (CAPM) analysis. His recommended ROE range based on his models, his consideration of market data, and his professional judgment is 8.90% to 9.60% with a midpoint of 9.25%.[19]

#### a. DCF Models.

DCF models are based on the assumption that a current stock price represents the present value of all future cash flows. Central to a DCF analysis is the dividend growth rate used in the model. All things being equal, the higher the growth rate, the higher the output of the model, and the higher the ROE the model recommends. Mr. Gorman utilized three types of DCF models, a constant growth DCF, a sustainable growth DCF, and a multi-stage DCF.

##### i. Constant Growth DCF Model.

A constant growth DCF model assumes that dividends and earnings will grow at a constant rate. The inputs to the model are a current stock price, an expected dividend, and an expected growth rate in dividends. For the current stock price input, Mr. Gorman used an average stock price because average prices are less susceptible to market variations than spot prices. Specifically, Mr. Gorman used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 10, 2016.[20] As explained in his testimony, this period reflects that the constant growth stock price input must be short enough to contain data that reflects current market expectations, but also be long enough to smooth out any aberrant market fluctuations.[21]

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[19]Gorman Direct at 54.
[20]*Id.* at 28
[21]*Id.*

For the dividend input, Mr. Gorman started with the most recently paid quarterly dividend as reported by *Value Line*, and then annualized it and adjusted it to account for next year's growth.[22]

With respect to the dividend growth rate, often the most contentious factor in a DCF model, Mr. Gorman used consensus professional security analysts' earning growth estimates from three sources, Zack's, SNL, and Reuters.[23] Based on these consensus projections, the average growth rate used for the proxy group is 5.38%.[24] As explained in Mr. Gorman's testimony, consensus analysts' growth projections are the best measure of investor expectations.[25]

The results of Mr. Gorman's constant growth DCF model show an average and median constant growth return for the proxy group of 8.83% and 8.89%, respectively for the 13-week analysis.

Mr. Hevert argues that Mr. Gorman's assumed growth rate is too low compared to high valuation levels.[26] But, as described, Mr. Gorman's growth rate is a consensus of analysts' projections, not his own. Hence, there should be no real dispute that analysts' growth rates are an accurate estimate of the market's growth expectations. Further, Mr. Gorman's assumed growth rate (5.38%) is actually higher than consensus analysts' projections of GDP growth (4.35%), which as explained below is the best proxy for a maximum long-term sustainable growth rate.[27]

With respect to the stock price valuation, Mr. Gorman cautiously used actual market data to reflect the dividend yield component of the DCF model. In other words, Mr. Hevert is essentially arguing against the reality of current market conditions, which reflect relatively high

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[22]*Id.* at 29.
[23]*Id.* at 30.
[24]*Id.*
[25]*Id.*
[26]Hevert Rebuttal at 70.
[27]Gorman Direct at 31.

stock prices, sustainably low dividend yields and, as a consequence, low costs of capital. Mr. Hevert's arguments for an increased cost of capital defy observable and verifiable market evidence.

### ii. Sustainable Growth DCF Model.

Mr. Gorman also performed a constant growth DCF model using sustainable growth rates. The sustainable growth model is an internal growth methodology that is based on the percentage of earnings retained by the utility and not paid out as dividends.[28] The theory of the model is that retained earnings allow a utility to invest in its rate base, and thus serve as a proxy for a growth rate that is sustainable.[29] Mr. Gorman's sustainable growth model showed an average sustainable growth rate for the proxy group of 4.26% for the 13-week period.[30] These growth rates, in turn, produce average and median DCF results for the 13-week period of 7.67% and 7.34%, respectively. Mr. Hevert did not specifically rebut Mr. Gorman's sustainable growth DCF model.[31]

### iii. Multi-Stage Growth DCF Model.

Mr. Gorman also performed a multi-stage DCF model, which captures expectations that a utility would have changing growth rates over time.[32] Mr. Gorman's multi-stage model reflected three growth periods: (1) a short-term growth period of five years, (2) a transition period for years six through ten, and (3) a long-term growth period starting in year 11 through perpetuity.[33] For the short-term period, Mr. Gorman relied on the consensus analysts' growth projections from his

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[28] *Id*. at 32-33.
[29] *Id*.
[30] *Id*. at 33.
[31] *Id*.
[32] *Id*.
[33] *Id*. at 34.

constant growth DCF model (5.38%).[34] For the second stage (i.e., the transition period), growth rates were reduced or increased by an equal factor, which reflected the difference between the analysts' growth rates and the GDP growth rate.[35] For the long-term period, he used consensus analysts' projected growth rate for the U.S. GDP (4.35%) as a proxy for the maximum sustainable growth rate for a utility company.[36]

Mr. Gorman used a GDP growth projection as a proxy for the maximum sustainable growth rate because, over the long term, a utility cannot be expected to sustain a growth rate that exceeds the growth rate of the economy into which it sells services.[37] As Mr. Gorman testified:

> Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas.[38]

Data from the U.S. Department of Energy Information Administration (EIA) confirms that utility growth largely tracks the U.S. GDP growth rate, but that utilities grow at a slower pace. Indeed, as demonstrated by Mr. Gorman's Exhibit MPG-10, GDP growth has outpaced utility sales growth for more than a decade.[39]

Mr. Gorman's conclusion is also supported by analysts and academic publications, which hold that dividends are generally expected to grow at about the same rate as the nominal GDP.[40] And it is supported by historical data showing that, from the period 1926-2015, the U.S. nominal

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[34] *Id.*
[35] *Id.*
[36] *Id.* at 37.
[37] *Id.* at 35.
[38] *Id.*
[39] FEA Witness Gorman, Exhibit MPG-10.
[40] *Id.* at 36 (quoting *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western at 298).

compound annual growth of the U.S. GDP exceeded the growth of the U.S. stock market.[41] Based on the foregoing, nominal GDP growth is a reasonable proxy for the highest sustainable long-term growth rate of a utility. If anything, the use of GDP growth as a proxy overstates the prospects for utility growth.

To determine the projected growth rate for the U.S. GDP, Mr. Gorman relied on the publication *Blue Chip Economic Indicators* (*Blue Chip*), which publishes consensus economists' GDP growth projections twice a year.[42] Because these projections are based on a consensus of analysts' views, they reflect all current outlooks and are the best available measure of the market's expectation of long-term GDP growth.[43] Specifically, Mr. Gorman used the projected 5- and 10-year average GDP consensus growth rates of 4.35% as an estimate of long-term sustainable growth.[44]

Notably, *Blue Chip's* projected growth rates are consistent with long-range forecasts from other sources. For example, the EIA forecasts real GDP growth through 2040, and its data produces a long-term nominal GDP growth outlook of 4.2%.[45] Moody Analytics projects nominal GDP growth of 4.1% over the next 30 years.[46] The Social Security Administration (SSA) makes economic projections out to 2090. Under its intermediate cost scenario for 50 years, SSA projects nominal GDP growth of 4.5%.[47] And the Economist Intelligence Unit, a division of *The Economist*, projects long-term nominal GDP growth of approximately 3.9% out to 2050.[48] Based

[41] *Id.* at 37 (citing *Duff & Phelps 2016 Valuation Handbook* inflation rate of 3.0%, and U.S. Bureau of Economic Analysis, January 29, 2016).

[42] *Id.* at 37.

[43] *Id*.

[44] *Id*.

[45] *Id*. at 38, Table 3.

[46] *Id*.

[47] *Id*.

[48] *Id*.

on all of this information, Mr. Gorman assumed a long-term sustainable GDP growth rate of 4.35%.

Mr. Gorman's multi-stage DCF model indicated an average ROE of 8.00% and a median of 8.01% for the 13-week period.[49] Mr. Hevert did not specifically address Mr. Gorman's multi-stage DCF model in his rebuttal testimony.[50]

**iv. Summary of DCF results.**

The results of Mr. Gorman's DCF models are as follows:

**TABLE 2**

**Summary of DCF Results**

| Description | 13-Week Proxy Group Average | 26-Week Proxy Group Average |
|---|---|---|
| Constant Growth DCF Model (Analysts' Growth) | 8.83% | 8.89% |
| Constant Growth DCF Model (Sustainable Growth) | 7.67% | 7.34% |
| Multi-Stage Growth DCF Model | 8.00% | 8.01% |
| Average | 8.17% | 8.08% |

Applying his professional judgment in light of all available data, Mr. Gorman concluded that these DCF results indicate a ROE of 8.90%, which is primarily based on the rounded median result of his constant growth model using consensus analysts' projections of growth. He reached this conclusion because the consensus analysts' projections of growth (5.38%) utilized in that model are reasonable when compared to the expected long-term sustainable growth rate, which for

[49]*Id.* at 40.
[50]Hevert Rebuttal at 69.

the reasons described above will converge on and not exceed the long-term projection of GDP growth (4.35%).

Unable to launch a credible attack on the results of these models, Mr. Hevert resorts to claiming that Mr. Gorman "discarded" his sustainable growth and multi-stage models and that this somehow renders all of Mr. Gorman's results unreliable. In a similar vein, Mr. Hevert states that Mr. Gorman applied weights to the results of his models. This is simply incorrect. Mr. Hevert can point to nothing in Mr. Gorman's testimony to indicate that he discarded these model results or that he mechanically applied weights to reach his ROE recommendation. Instead, Mr. Gorman considered all model results and all relevant market data in making his recommendations.

For all these reasons, Mr. Gorman's DCF estimate of a required return on equity for FPL of 8.90% is reasonable and, in fact, conservative.

**b. Risk Premium Model.**

Mr. Gorman also utilized a risk premium model, which is based on the concept that investors require a higher return to assume greater risk.[51] The purpose of the model is to estimate the premium that investors require to invest in a utility stock compared to lower risk, non-equity investments. Mr. Gorman's model was based on two estimates of an equity risk premium. First, he estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds for the period 1986 through 2016.[52] This produced an average indicated equity risk premium of 5.46% with a five-year rolling average equity risk premium ranging from 4.25% to 6.71%.[53]

[51]Gorman Direct at 41.
[52]*Id.*
[53]*Id.* at 42.

The second equity risk premium estimate was based on the difference between regulatory commission-authorized returns on common equity and contemporary Moody's "A" rated utility bond yields for the period 1986 through 2016.[54] This produced an average equity risk premium of 4.08%, with a five-year rolling average premium ranging from 2.88% to 5.53%.[55] In order to mitigate the impact of anomalous market conditions and better capture the risk premium over an entire business cycle, Mr. Gorman used the five-year rolling averages for both the Treasury bond and utility bond estimates.[56]

To arrive at a recommended cost of equity from his risk premium for his Treasury bond estimate, Mr. Gorman next added a projected long-term Treasury bond yield (*Blue Chip's* 30-year projection of 3.40%) to a weighted equity risk premium over Treasury yields of 6.09%, which produced a common equity return of 9.50%.[57] With respect to the utility bond estimate, Mr. Gorman added his weighted average estimated equity risk premium of 4.87% to a current 13-week average yield on "Baa" rate utility bonds for the period ending June 10, 2016 (4.69%), resulting in a cost of equity of 9.59%.[58]

Mr. Gorman's recommendation considers both utility security risk and market interest rate risk. Thus, on the one hand, it reflects that the market currently considers utility investments as low risk. To be conservative, Mr. Gorman applied 75% weight to the high end of his risk premium estimates and 25% weight to the low end.[59] This results in a risk premium estimate over U.S. Treasury bond yields of 9.50% and a risk premium over "Baa" utility yields of 9.59%.

[54]*Id*.
[55]*Id*. at 43.
[56]*Id.* at 42.
[57]*Id.* at 47.
[58]*Id*.
[59]*Id*.

Accordingly, Mr. Gorman's risk premium analysis yields a return estimate in the range of 9.50% to 9.59%, with a rounded midpoint of 9.60%.[60]

In his rebuttal testimony, Mr. Hevert argues that Mr. Gorman's risk premium analysis is flawed because it is inconsistent with the notion of an inverse relationship between a risk premium and interest rates.[61] In other words, Mr. Hevert believes that as interest rates go down, the premium that investors require to invest in utility stocks must go up. But academic studies do not support the existence of a simplistic inverse relationship. As Mr. Gorman testified:

> While academic studies have shown that, in the past, there has been an inverse relationship among these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[62]

Indeed, even the studies cited by Mr. Hevert[63] do not support his conclusion. For example, while Brigham et al. found an inverse correlation between risk premiums and interest rates beginning in 1980, they also found that the opposite had been true prior to that time.[64] And as discussed by Robert Harris, another author cited by Mr. Hevert, the Brigham study "did not provide direct empirical proxies for changes in equity risks that would explain changes in equity risk premia over time."[65]

Instead of a simplistic inverse relationship, the literature shows that risk premiums change over time based not only on the level of interest rates, but also on other factors such as the spread between corporate and government bond yields and the dispersion of analysts' forecasts.[66] The

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[60]*Id*.

[61]Hevert Rebuttal at 78.

[62]Gorman Direct at 66.

[63]*Id*. at 67.

[64]*Id*.

[65]Hevert Rebuttal, footnote 41 at 25. Robert S. Harris, Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return, *Financial Management*, Spring 1986 at 64;

[66]*Id*. Robert S. Harris, Felicia C. Marston, Estimating Shareholder Risk Premia Using Analysts'

academic studies conclude that "[o]ne would expect changes in measured equity risk premia to be related to changes in perceived riskiness."[67] Neither logic nor academic findings support Mr. Hevert's assertion that the premium investors require to purchase stocks compared to debt securities is based purely on the level of interest rates.

In sum, changes in risk premiums are attributable to changes in the perceived relative investment risk of equity and debt securities based on current market conditions.[68] Because Mr. Hevert ignores investment risk differentials in favor of a simplistic inverse relationship between an equity risk premium and interest rates, his criticism of and adjustment to Mr. Gorman's risk premium model should be rejected.

**c. CAPM.**

Mr. Gorman also ran a CAPM analysis to estimate FPL's cost of equity. CAPM is based on the concept that the market-required rate of return for a security equals the risk-free rate plus a risk premium associated with the specific security.[69] The inputs for Mr. Gorman's CAPM are (i) an estimate of the market risk-free rate, (ii) the company's beta, and (iii) the market risk premium.

For the risk-free rate, Mr. Gorman used *Blue Chip's* projected 30-year Treasury bond yield of 3.40%.[70] This is a reasonable proxy for the risk-free rate because Treasury securities are backed by the full faith and credit of the U.S. government and thus have negligible credit risk. Moreover, long-term treasury bonds have a similar investment horizon to common stock, meaning that both reflect investor expectations of long-term inflation.[71]

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Growth Forecasts, *Financial Management*, Summer 1992 at 68.

[67] *Id*.

[68] Gorman Direct at 66-67.

[69] *Id*. at 48.

[70] *Id.* at 49.

[71] *Id*.

The "beta" is the investment risk of a specific stock that cannot be diversified away when the stock is held in a diversified portfolio.[72] For this input, Mr. Gorman used *Value Line* estimates for the proxy group companies.[73]

With respect to the market risk premium, Mr. Gorman developed two estimates, one forward looking and one based on a long-term historical average. Mr. Gorman derived the forward-looking estimate by estimating the expected return on the S&P 500 and subtracting the risk-free rate. Mr. Gorman obtained the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. Specifically, Mr. Gorman used Duff & Phelps's average real market return over the period 1926 to 2015 (8.7%), and added that to the current consensus analysts' inflation projection as measured by the Consumer Price Index (2.3%), resulting in an expected market return of 11.20%. Subtracting the risk-free rate of 3.40% from this return yields a market risk premium of 7.80% for the forward-looking analysis.[74]

For the historical estimate of the market risk premium, Mr. Gorman started with Duff & Phelps's estimated arithmetic average of the achieved total return on the S&P 500 from 1926 to 2015 (12.0%) and subtracted the total return on long-term Treasury bonds (6.0%).[75] This results in a market risk premium of 6.0%. The average of Mr. Gorman's two market premium estimates is thus 6.90% (6.0% to 7.8%).[76] Mr. Gorman confirmed the veracity of his estimates by comparing them to Duff & Phelps's market risk premiums, which are in the range of 5.5% to 6.9%.[77] Duff & Phelps's analysis thus assumes that investors demand a lower risk premium to invest in utility

[72] *Id.* at 48.
[73] *Id.* at 50.
[74] *Id.* at 50-51.
[75] *Id.* at 51.
[76] *Id.*
[77] *Id.*

stocks than does Mr. Gorman's. This is evidence that Mr. Gorman's market risk premiums are reasonable.

Mr. Gorman's CAPM analysis produces a return in the range of 7.90% to 9.25%. Due to the relatively low historical level of risk-free rates, Mr. Gorman concluded a reasonable CAPM cost of equity estimate is 9.25%.[78]

Mr. Hevert's primary criticism of Mr. Gorman's CAPM model is that Mr. Gorman's assumed market returns of 9.40% to 11.20% are lower than the 50-year rolling average market return from 1976 through 2015, covering annual market returns for the 1926 through 2015 period.[79] However, forward market returns are expected to be lower than historical market returns because, if for no other reason, future inflation growth is expected to be lower than historical realized inflation. For the referenced 1926 to 2015 period, the average inflation rate was 3.00%, meaning that the average market return from that period without inflation was approximately 8.9%. The current expected market inflation rate is 2.3%. When the 2.3% current inflation rate is added to the 8.9% historical market return, the average market return drops from 12.0% to 11.20%, which is exactly the market return assumed at the high end of Mr. Gorman's range. Mr. Gorman's CAPM results are thus consistent with historical market returns. The results are also consistent with outlooks for expected market returns and market risk premium estimates.

[78]*Id.* at 53.
[79]Hevert Rebuttal at 74.

**d. Summary of ROE analyses.**

The results of Mr. Gorman's analyses are set out below:[80]

**TABLE 3**

**Results of Mr. Gorman's ROE analysis**

| Description | Results |
|---|---|
| DCF | 8.60% |
| Risk Premium | 9.60% |
| CAPM | 9.25% |

Based on the results of these analyses, Mr. Gorman's recommended range for FPL's ROE is 8.90% to 9.60%, with a midpoint of 9.25%. The low end of this range is based on the DCF results, while the high end is the based on the risk premium studies. The results of Mr. Gorman's CAPM study (9.25%) is within the range of his DCF and Risk Premium study results. An ROE of 9.25% would fairly compensate investors for FPL's total investment risk. And, as set out in detail in Mr. Gorman's testimony, it would preserve FPL's financial integrity and support an investment grade bond rating for the company. Mr. Gorman's ROE recommendation should be adopted.

**4. Mr. Hevert's recommendation.**

Mr. Hevert's recommended range of 10.50% to 11.50%, with a point estimate of 11.00%, is inflated. Mr. Hevert's analysis is flawed for the reasons summarized below. There is no indication that Mr. Hevert changed his methodologies when he conducted his update, excluding

[80] Gorman Direct at 54.

changes to his updated proxy group, so these flaws are present in both his direct-testimony and rebuttal-testimony analyses.[81]

**a. Constant Growth DCF.**

Mr. Hevert's constant growth DCF assumes unreasonable growth rates for his high-end estimate. Specifically, the proxy group growth rate for the high-end is 6.22%, which is substantially higher than analysts' growth outlooks, even over the next three to five years.[82]

However, Mr. Hevert's mean DCF results, excluding his 12 basis point flotation cost adder, of 9.19% to 9.30% are more reasonable. With this correction, Mr. Hevert's constant growth DCF model produces ROE estimates of 9.19% to 9.30%, with a midpoint of approximately 9.25%. These corrected results are reasonable and in-line with Mr. Gorman's recommended range.

**b. Multi-Stage Growth DCF.**

The first problem with Mr. Hevert's multi-stage DCF model is that it uses an inflated long-term growth rate. To come up with his long-term rate input, Mr. Hevert simply takes the historical GDP growth rates for the period from 1929 to 2014 and adds a current inflation rate to create a nominal GDP growth rate.[83] The historical real GDP growth rate is 3.25%, and Mr. Hevert used an inflation rate of 2.04%. This produces a 5.35% nominal GDP growth rate. As an initial matter, Mr. Hevert fails to explain the basis of his assumption that a historical real GDP growth rate is appropriate for projecting future growth. The world economy has changed a great deal since 1926, and Mr. Hevert has provided no credible evidence that the U.S. economy will simply grow at the

[81]Because Mr. Hevert has not abandoned his direct testimony model outputs, the numbers referenced below are based on his direct testimony.
[82]Gorman Direct at 69, Exhibit MPG-5.
[83]Hevert Direct at 35.

exact same rate in the future that it has in the past. Nor has he provided evidence that investors expect the historical rate to prevail in the future.

Further, Mr. Hevert's use of a historical real GDP growth rate is inflated in light of current economic outlooks. As Mr. Gorman demonstrated in the following chart, Mr. Hevert's historical real GDP growth rate is significantly higher than independent consensus economists' projections of long-term GDP growth in the future:

**TABLE 4**

**GDP Projections**

| Description | GDP Inflation | Real GDP | Nominal GDP |
|---|---|---|---|
| Mr. Hevert | 2.0% | 3.3% | 5.35% |
| Consensus Economists (5-Year) | 2.1% | 2.2% | 4.35% |
| Consensus Economists (10-Year) | 2.2% | 2.2% | 4.35% |

Mr. Hevert can cite no analysts' projections of long-term GDP growth that are consistent with his inflated estimate. Because his historically derived GDP growth rate overstates future long-term growth, Mr. Hevert's multi-stage DCF model overestimates the cost of equity for the proxy group.

Mr. Hevert's multi-stage DCF model should be rejected for an additional reason: it assumes his proxy group's 3-5 year projected payout ratio of 61.7% will increase to a terminal payout ratio of 67.30%. There is simply no reason to expect the dividend payout ratio of the proxy group will increase toward the historical utility industry average. The going forward payout ratio of the proxy group will be controlled by funding requirements and dividend growth outlook for the future.

Utilities are reducing dividend payout ratios in order to increase retained earnings as a means to increase internal cash flow. This increased internal cash flow supports the utility's ability to fund larger capital expenditure programs with internal funding. Since the capital expenditure program for the industry is expected to remain large, there is no reasonable basis to assume that the industry payout ratio will increase during Mr. Hevert's transition period growth stage.

There is simply no basis for the assumption that the dividend payout ratio will increase or change between growth stages of this model.

For all these reasons, Mr. Hevert's multi-stage DCF model produces an exaggerated return estimate. Mr. Gorman testified that Mr. Hevert's model could be corrected if (i) consensus analysts' projections were used for the GDP growth rate and (ii) Mr. Hevert's dividend payout ratio assumption was made consistent with the assumed long-term earnings growth rate. Applying these changes to Mr. Hevert's multi-stage DCF reduces the estimated return from 9.8% to 8.7%.

**c. CAPM.**

Mr. Hevert's CAPM analysis is flawed because it uses an inflated market risk premiums of 10.68% (Bloomberg) and 9.87% (*Value Line*).[84] These premiums are based on market DCF returns of 13.63% and 12.82%, respectively. The DCF returns, in turn, include stock market index growth rates of approximately 11.24% and 10.58%.[85] As explained in Mr. Gorman's testimony, the DCF model requires the use of a long-term sustainable growth rate, but 11.24% and 10.58% are far too high to be a reasonable outlook for sustainable long-term stock market growth.[86] Indeed, these rates are more than double consensus analysts' projections of GDP growth (4.35%).

[84]Hevert Direct Exhibit RBH-2.
[85]Gorman Direct at 63.
[86]*Id.*

Because Mr. Hevert's long-term market growth rate estimates are unreasonably high, his CAPM analysis produces an inflated return. Mr. Gorman testified that Mr. Hevert's CAPM analysis could be adjusted to provide a more reasonable result. Specifically, using (i) Mr. Hevert's more recent 2017 projected risk free rate, (ii) beta estimates of .608 and .776 (which are the averages published by Bloomberg and *Value Line*), (iii) a market premium of 7.80% as used in Mr. Gorman's CAPM study, and (iv) excluding Mr. Hevert's flotation cost adder, results in a CAPM estimated return in the range of 7.46% to 9.45%.

**d. Bond Yield Risk Premium.**

Mr. Hevert also ran a bond yield risk premium model, which is based on his assumption that there is an inverse relationship between the level of interest rates and the equity risk premium. Mr. Hevert starts with an average electric risk premium of 4.50% over the period January 1980 to January 2016. However, based on the purported inverse relationship, Mr. Hevert then applies a regression analysis to Treasury bond yields to increase this risk premium to a range of 5.73% to 7.08%. This is how he arrives at his ROE estimates in the range of 10.04% to 10.53%.

As discussed above, Mr. Hevert's assumption of a simple inverse relationship is inaccurate. Academic findings support the common-sense notion that investors look at the totality of risk when deciding whether to purchase a stock or a debt security and do not rely exclusively on the level of interest rates. Accordingly, Mr. Hevert's attempt to use a regression analysis to increase the risk premium he calculated should be rejected. Applying Mr. Gorman's weighted average equity risk premium over Treasury yields of 6.09% to Mr. Hevert's current Treasury yield of 2.72% and a near-term projected yield of 3.40%, would produce a cost of equity of no higher than 9.50%.

**5. Summary of ROE .**

For all of the foregoing reasons, Mr. Hevert's recommendation should be rejected. FEA requests that the Commission adopt Mr. Gorman's recommendation of an ROE of 9.25% for FPL.

## OKEECHOBEE ENERGY CENTER CAPITAL STRUCTURE

**STATEMENT OF POSITION:**

**ISSUE 129: What is the appropriate weighted average cost of capital, including the proper components, amounts and cost rates associated with the capital structure, to calculate the limited scope adjustment for the new Okeechobee Energy Center?**

**FEA:** A 2019 increase to rates should not be granted. However, should the 2019 rates be altered, the 2018 test year ratemaking capital structure should be used to calculate the weighted average cost of capital for the Okeechobee Energy Center. As recommended by FEA witness Gorman, the appropriate weighted average cost of capital is 5.56%.

**DISCUSSION:**

FPL is proposing to use only the permanent capital portion of its capital structure for ratemaking purposes for the Okeechobee Energy Center ("Okeechobee").[87] The resulting capital structure is approximately 60% common equity and 40% debt.[88] FPL's proposed capital structure for Okeechobee ignores all customer-supplied capital including customer deposits, and zero-cost capital components related to deferred income taxes and investment tax credits. This has the effect of increasing the rate of return that would be applied to the $1.06 billion investment projected at May 31, 2020.[89]

FPL's proposed capital structure for the Okeechobee investment is unreasonable. This investment is not expected to into service in 2019. Over this time period, FPL's invested capital will change dramatically based on the rates set in 2017 and modified again in 2018.[90] As such,

[87]Okeechobee Clean Energy Center Limited Scope, Vol. 1, Schedule D-1a.
[88]*Id*.
[89]Gorman Direct at 20-21.
[90]Gorman Direct at 21.

the incremental change in rates in 2019 for this investment should be based on the same regulatory capital structure used to set the revenue requirement for the rest of its investments.

FPL's proposed capital structure inappropriately inflates its revenue requirement by approximately $34.8 million.[91] The Commission should reject FPL's proposed capital structure for its Okeechobee investment.

## DEPRECIATION RATES AND EXPENSE

**STATEMENT OF POSITIONS:**

**<u>ISSUE 45</u>: What are the appropriate depreciation parameters (e.g., service lives, remaining lives, and net salvage percentages) and resulting depreciation rates for each transmission, distribution, and general plant account, and subaccounts, if any?**

**<u>FEA</u>:** FEA has only taken a position on the average lives for Accounts 362, 365, and 369.1; for all other accounts, FEA takes no position. The appropriate survivor curve for Account 362 is the 51-S0.5, which results in a depreciation rate of 2.04%. The appropriate survivor curve for Account 365 is the 57-R1, which results in a depreciation rate of 3.00%. The appropriate survivor curve for Account 369.1 is the 56-R1.5, which results in a depreciation rate of 4.08%. (Andrews)

**<u>ISSUE 47</u>: If the Commission accepts FPL's depreciation study for purposes of establishing its proposed depreciation rates and related expense, what adjustments, if any, are necessary?**

**<u>FEA</u>:** FEA has recommended explicit adjustments, which are detailed in Issue 45 and result in a 2017 depreciation expense reduction of $22.5 million. (Andrews) Adjustments stemming from FEA's adoption of OPC's position on Issues 40, 41, 42, 43 and 46 are addressed in those issues.

**DISCUSSION:**

FPL's witness Mr. Ned Allis filed a depreciation study for FPL's plant balances as of 12/31/2017. With the exception of three distribution accounts, these filed rates and their corresponding expenses are fair and reasonable. The resultant annual depreciation expense for

[91] *Id.*

plant balances as of December 21, 2017, as filed in Mr. Allis' direct testimony is $1,645.2 million[92] or an increase of $221.3 million[93] to the 2017 test year depreciation expense.

Mr. Brian Andrews on behalf of FEA filed testimony stating that FPL overstated its depreciation rates for three distribution accounts. These rates produce an excessive amount of depreciation expense and overstate the test year revenue requirement.

FEA believes that FPL has underestimated the average service lives of threes distribution accounts, Accounts 362, 365, and 369.1, due to its reliance on fitting survivor curves to a set of data containing outdated retirement history. The average service lives for these three accounts should be based on the more recent retirement history contained in the original life tables reflecting the retirement history form 1995-2014 rather than 1941-2014.[94]

Mr. Allis is his rebuttal testimony has suggested that the use of retirement history from 1995 from 2014 includes unusual events that unlikely to reoccur.[95] He attempts to display the unusual characteristics of additions and retirements during the "Great Recession" by portraying bar graphs which show the level of additions and retirements for Account 362 between 1980 and 2014.[96] What is shown clearly in these bar graphs are 3 distinct cycles of growing and shrinking retirements and additions, two of which occur within the study period Mr. Andrews has suggested to use. There is no reason to suggest that this type of cyclical nature of retirements and additions will not occur in the future. In every decade there are major events that change the course of a utility's spending and retirement behavior. In 1992, Hurricane Andrew devastated Florida. In the late 1980s there was the savings and loan crisis. In the 1970s, there was the oil embargo and the

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[92]Exhibit NWA-1, Page 90 of 762.
[93]*Id*.
[94]Brian Andrews direct testimony at Page 2, lines 8-17.
[95]Ned Allis Rebuttal at Page 108 Line 22 – Page 109 Line 1.
[96]Ned Allis Rebuttal at Page 111 Figure 11 & Page 112 Figure 12.

end of the Vietnam War.  And the two decades that followed WWII, the US saw substantial economic growth and expansion.  There is no reason to suggest that major events will not continue to occur in every decade going forward.  Additionally as Mr. Andrews pointed out on cross examination, the majority of the property in this account has been installed after 1995[97] and more recent retirement history will provide a better indication of the lives that will be experienced by the current property in the future.[98]

FPL's reliance on retirement history that spans the 74 years between 1941-2014 has averaged out any trends of increased lives that can be seen for these three accounts.[99]  Mr. Andrews' has presented  reasonable and fair adjustment to the average service lives and resulting depreciation rates for accounts 3625, 365, and 369.1.  The appropriate depreciation rate for Account 362 is 2.04%.  The appropriate depreciation rate for Account 365 is 3.00%, and the appropriate depreciation rate for account 369.1 is 4.08%.  The total impact on the 2017 depreciation expense is a reduction of $22.5 million.

## COST ALLOCATION – COST OF SERVICE

**STATEMENT OF POSITIONS:**

**ISSUE 136: What is the appropriate methodology to allocate production costs to the rate classes?**

**FEA:** If the Commission approves a change from the 12 CP and 1/13th method, a 100% demand-based method using a summer 4 CP or summer/winter 4 CP / 1 CP is most appropriate.  FPL's proposed 12 CP and 25% method should be rejected. Continuance of the 12 CP and 1/13th method is a compromised approach.

**ISSUE 137: What is the appropriate methodology to allocate transmission costs to the rate classes?**

[97]Transcript Page 3971, Lines 24-25.
[98]Transcript Page 3972, Lines 21-24.
[99]Transcript Page 3961, Lines 18-21.

**FEA:** FPL's proposed 100% demand-based 12 CP method is appropriate.

**ISSUE 138: What is the appropriate methodology to allocate distribution costs to the rate classes?**

**FEA:** FPL should perform a Minimum Distribution Study of its system in order to properly account for the customer-related portion of proper distribution cost allocation in its next base rate proceeding.

**DISCUSSION:**

FPL has proposed a change to its longstanding 12 CP and $1/13^{th}$ production allocation method, to increase the percentage of demand-related production costs allocated on an energy basis from 7.7% ($1/13^{th}$) to 25%. FPL proposes to continue its longstanding practice of allocating energy-related production costs on an energy basis. FPL's change to the allocation method for demand-related production costs should be rejected by the Commission, because the method does not align with cost of service for FPL's production (generation) asset fleet, and FPL's supporting evidence is flawed and insufficient.

FPL's proposed transmission cost allocation method follows cost of service and should be approved. FPL's distribution cost allocation method ignores the customer-related portion of costs beyond the customer meter and service drop that do not vary with customers' load demands. The Commission should order FPL to conduct a study prior to its next base rate case to determine the appropriate percentage of its distribution costs that are customer-related.

### 1. Transmission Plant Costs

FPL proposes to use the 12 coincident peak ("CP") 100% demand allocation method to allocate transmission plant costs, excluding generator step-up costs and transmission pull-off costs. The Company's proposal is consistent with cost-causation principles, and follows the allocation approved by the Florida Public Service Commission ("Commission") for other Florida IOUs.[100] No party objects the Company's using a 100% demand-related allocation method for transmission plant costs.[101]

The Company proposes to allocate its generator step-up costs as a production-related investment, which FEA supports. The Company proposes to directly assign transmission pull-off costs to the transmission service voltage customers and allocate between customers using a customer-related allocator, which FEA supports.

**2. Production Plant Costs**

FPL specifically, and Florida IOUs generally, have historically relied upon the 12 CP and $1/13^{th}$ method to allocate demand-related production plant costs. This method classifies $1/13^{th}$ of the production costs as energy-related, and allocates those costs on energy requirements. The remaining $12/13^{ths}$ are classified as demand-related and allocated to classes on the average of the classes' 12 coincident peaks. FPL proposes to switch to the 12 CP and 25% method from the 12 CP and $1/13^{th}$ method. The result of this change is that a greater percentage of the demand-related production plant costs would be allocated on an energy basis. FPL's proposed change increases the amount of demand-related costs allocated on an energy basis from approximately 7.7% ($1/13^{th}$) to 25%. In its 2012 base rate case, FPL proposed using the 12 CP and $1/13^{th}$ method for production cost allocation.[102]

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[100]Direct Testimony of FPL witness Deaton, page 23, lines 3-6.
[101]Prehearing Order, Issue 137, pages 199-200.
[102]Docket No. 120015-EI, Direct Testimony of FPL witness Ender, page 21.

**2.a. Fuel Savings Argument**

The Company argues that it has reduced the overall heat rate of its generation fleet, creating fuel cost savings for its ratepayers.[103] FPL compares the increased cost allocation to large commercial and industrial classes under the proposed 12 CP and 25% method versus the 12 CP and 1/13th method to the total fuel cost savings it claims these large customer classes have received as a result of the Company's heat rate improvements.[104] FPL concludes that these large customers are receiving a fuel cost benefit that is greater than the additional production costs they are being allocated, and that therefore the 12 CP and 25% allocation method is justified.[105] FPL's arguments here seek to allocate costs based on alleged benefits received, rather than based on cost incurrence. FPL has not presented any evidence that it has recently, or will in the future, incur production costs in any way different from in previous years where FPL supported the 12 CP and 1/13th method as reasonable. FPL claims that its recent generation additions have been baseload and intermediate load units,[106] but does not claim that these additions are different from the Company's generation additions prior to 2012 in order to support any notion of a change in cost causation. Instead, FPL simply argues that the generation additions have brought heat rate efficiencies and fuel savings benefits to customers.[107] FPL's proposal to allocate costs to customer classes based on the alleged fuel savings is not reasonable, and is contrary to proper cost allocation methodology based on cost incurrence.

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[103] Direct Testimony of FPL witness Deaton, page 21, lines 21-23.
[104] Exhibit RBD-8.
[105] Transcript Volume 35, page 5415, lines 2-6.
[106] Direct Testimony of FPL witness Deaton, page 21, lines 18-21.
[107] Rebuttal Testimony of FPL witness Deaton, page 7, lines 13-15.

**2.b. Florida Commission Precedent Argument**

FPL relies on what it claims is precedent set in other Commission orders and Staff recommendations supporting an energy weighting of greater than 1/13th.[108] Both cases cited by FPL, Tampa Electric Company ("TECO") Docket No. 080317-EI and Duke Energy Florida ("DEF") Docket No. 090079-EI, were filed and concluded prior to 2012, prior to FPL's last base rate case in which is continued to support the 12 CP and 1/13th method. In addition, comparisons between other Commission Orders and FPL's case in this proceeding are inconclusive since the value of the fuel savings in the other IOU cases cited by FPL has not been quantified in the case record. FPL's main argument for changing the production cost allocation method rests on the amount of fuel cost savings it has garnered for customers in recent years, but it has provided no benchmarking to the amount of fuel cost savings that TECO or DEF provided to its customers leading the Commission and Staff to recommend the 12 CP and 25% allocation methodology. The mere fact that FPL is replacing its aging generation units with more modern and fuel-efficient units is not cause to change the production cost allocation method, because Good Utility Practice[109] suggests that FPL should continually be contemplating the economics of replacing aging generation and acting in the best interest of the ratepayers. FPL should have been contemplating these generation investments during the decades that it supported the 12 CP and 1/13th methodology, and therefore these prudent investment decisions are not cause for a change in cost allocation among the rate classes.

[108]*Id*., page 8, lines 18-22.
[109]The term is defined in FERC Order 888.

**2.c. Capital Substitution Theory Argument**

FPL's claim that its recently installed baseload and intermediate load generation costs more to construct but less costly to operate over time than peaking generation[110] alludes to the theory of capital substitution suggesting that when a utility chooses to install a baseload generating unit with a higher upfront capital cost but lower fuel costs over time, as opposed to a peaking unit with a lower fixed capital cost but higher fuel cost, it can be argued that the utility is substituting demand-related capital costs to obtain fuel savings. The thinking is that, therefore, the capital expenditure that generates these fuel savings could be allocated like a fuel expense, on an energy basis. But the theory of capital substitution predicating the Company's arguments has actually weakened in recent years, as fuel prices and generation costs have changed. Capital substitution was historically predicated on the relative capital and fuel cost differential between baseload (coal-fired or nuclear) units and peaking (gas-fired or oil-fired) units. Specifically, the theory posits that a high capital cost baseload coal-fired unit can be the least cost generating addition, versus a lower capital cost gas-fired peaking unit, because of the coal unit's lower fuel operating cost. But in recent years, and for the foreseeable future, FPL is relying on natural gas to fuel its baseload and intermediate units.[111] Therefore, both the high capital cost baseload units and the lower capital cost peaking units that FPL considers when adding new generation to its fleet are gas-fired, negating the fuel savings between asset types based on fuel-type differences.

Further, the historical capital cost differential between combined-cycle baseload units and combustion turbine peaking units is about four times, but the current differential is only approximately two times.[112] Therefore, the trade-off between higher capacity costs and lower fuel

[110]Direct Testimony of FPL witness Deaton, page 21, lines 18-21.

[111]Direct Testimony of FEA witness Alderson, Table 1 on page 13; Transcript Volume 8, page 826, lines 15-18; and FPL 2016 IRP, page 57.

[112]Direct Testimony of FEA witness Alderson, page 14.

costs is far more muted in today's market than in 2012 when FPL proposed continuation of the 12 CP and 1/13$^{th}$ allocation method, and for the nearly thirty years prior that FPL used the 12 CP and 1/13$^{th}$ method.[113]

This weakening of the capital substitution theory should result in a decrease in the energy allocation percentage of total production costs, not an increase as the Company has proposed. Historically, the capital substitution could apply if a utility were to elect to install a baseload unit at four-times the cost of a peaking unit, in order to receive fuel savings from the coal-fired baseload unit which was cheaper than the fuel cost of the gas-fired peaking unit. Today, FPL has elected to install baseload units at only two-times the cost of a peaking unit, and receives no fuel savings from differences in fuel types because it uses natural gas to power both the baseload units and peaking units. For FPL to rely on the theory of capital substitution to support an increase in the energy-weighting of the production allocation factor is unfounded.

FPL counters that its reliance on natural gas to power both baseload and peaking units is irrelevant, and that its fuel savings from heat rate efficiencies still merits an increase in the energy-weighting of the production allocation factor from 7.7% to 25%.[114] But FPL has not provided any analytical support comparing fuel savings in the past versus today, no matter whether the savings are from either heat rate efficiencies, or fuel-type trade-offs, or both, to identify specifically whether an allocation factor increase from 1/13$^{th}$ to 25% is merited.[115] Again, following Good Utility Practice, FPL would have been investing in generating unit upgrades and capital projects to bring savings to ratepayers during the decades that FPL supported the 12 CP and 1/13$^{th}$ method, same as it has done over the past four years since its last base rate case. Its recent capital projects

[113] Rebuttal Testimony of FPL witness Deaton, page 6, lines 22-23.
[114] *Id.*, page 12, lines 6-8.
[115] *Id.*, page 8, lines 8-10.

have not been shown to be any different than projects in the past in any way that would support a change in the allocation of these costs across customer classes.

**2.d. FPL System Planning Argument**

FPL's proposal to increase the energy-weighting in the production cost allocation method is inappropriate for two additional reasons, besides the weakening of the capital substitution theory described above. First, in its 2014 IRP, the Company added a third reliability criterion for production planning, a 10% generation-only reserve margin, applied to the one summer coincident peak hour and the one winter coincident peak hour. FPL therefore has increased its emphasis on planning to meet its peak demand needs, not its energy needs in every hour. Historically, up until 2014, FPL used two criteria to determine the amount of generating capacity needed to operate the system safely and reliably. The first criterion relies on a minimum 20% peak period reserve margin for the summer (August) and winter (January) peak hour, the second relies on a maximum loss of load probability ("LOLP") of 0.1 day per year.[116] FPL increasing its emphasis on planning to meet its peak demand needs through the 10% and 20% reserve margin criteria supports FEA's opposition to the Company's proposed increase in the energy-weighting of the allocation factor.

Second, FPL's system load characteristics show that the Company has a 4 coincident peak pattern, not a 12 CP pattern. Allocating the demand-related production costs on a 12 CP basis, which the Company does, when a 4 CP is more appropriate, exacerbates the problem of allocating costs in a way that is not reflective of cost incurrence, when coupled with the Company's proposal to increase the energy-weighting factor when a decrease is merited. Allocating demand costs on a 12 CP basis when a 4 CP is more reasonable moves cost allocation further from cost incurrence, and increasing the energy-weighting factor in the production allocator from 1/13th to 25% similarly

[116]FPL 2016 IRP, pp. 35 and 52.

moves cost allocation further from cost incurrence. Continuing the practice of using a 12 CP factor to allocation the demand costs is cause for also continuing to place a 1/13th, or less, weighting on the energy-related factor, to be sure the production cost allocation method moves no further away from cost incurrence than it currently is.

FEA advocates for a 100% demand-based production allocation method, based on either the 4 summer coincident peaks, or 4 summer and 1 winter coincident peak. Continuation of the Florida long-standing precedent of allocating production demand cost using a 12CP and 1/13th method could be considered a compromised approach between FEA's and the Company's proposed methodologies.

**3. Distribution Plant Costs**

FPL proposes classifying all distribution plant costs, except for meters and service drops, as demand-related, as opposed to including a customer-related component when allocating distribution costs to the various customer classes. But distribution costs for poles, towers, overhead and underground lines, and line transformers are not wholly based on the total maximum demand expected to be placed on the asset. FPL has an obligation to connect any new customer within its service territory, regardless of the maximum demand of the customer,[117] which requires FPL to install assets such as poles, wires, or transformers, simply to connect the customer.

The portion of distribution plant in each plant asset category, be it poles or overhead or underground wires, etc., that is determined to be not based on maximum demand is a matter of judgment, according to the NARUC Manual.[118] But nevertheless, FPL has not supported their contention that none, 0%, of the distribution plant costs in the FERC Accounts in question are

[117]FPL Rules and Regulations Section 2.2.
[118]Direct Testimony of FEA witness Alderson, page 21, lines 1-9.

unrelated to maximum demand. The NARUC Manual proposes multiple methods for analytically surveying the utility system to determine the amount of asset costs not based on maximum demand.[119] FEA supports the use of a Minimum Distribution Study to determine the appropriate cost segmentation as it is widely used in jurisdictions across the country, and by other IOUs in Florida.[120] FEA proposes that the Commission order FPL to conduct a Minimum Distribution Study of its system, survey the use of the Minimum Distribution Study in other similarly-situated utilities across the country, with similar customer load characteristics and geographical make-up, and present the findings of these studies to Staff and other interested parties prior to FPL's next base rate case filing.

## SPREAD OF THE APPROVED REVENUE INCREASE/DECREASE

**STATEMENT OF POSITION:**

**ISSUE 140: How should the change in revenue requirement be allocated to the customer classes?**

**FEA:** If the Commission orders an overall revenue increase, FPL's proposed gradualism constraints of no more than 1.5 times the system average increase and no less than 0.5 times the system average increase is appropriate, but should be calculated on the basis of total class revenue, including all surcharges except for the fuel surcharge. If the Commission orders an overall revenue decrease, all classes should receive an equal percentage reduction calculated on the basis of total class revenue, including all surcharges, but excluding fuel charges.

**DISCUSSION:**

FPL recommends that its requested overall revenue increase be spread to rate classes based on its retail cost of service study results to bring all classes to parity (equal to their respective cost

[119] *Id.*, Lines 1-5.

[120] FEA Response to FPL's First Set of Interrogatories, Number 6; and Direct Testimony of SFHHA witness Baron, pages 40-41.

of service), except that no class should receive a rate decrease, nor shall any class receive a rate increase greater than 1.5 times the system average increase. These two gradualism constraints are common in the industry, and FEA supports them in this proceeding, but objects to FPL's application method of including all rate revenues to determine the 1.5 times system average increase maximum. All rate revenues include the base rate revenues at issue in this case plus all surcharge revenues excluded from this case proceeding.

For the 2017 Test Year, FPL's proposed base rate revenues total $6.8 billion,[121] forecasted fuel revenues are $3.1 billion, and estimated other clause revenue is $1.5 billion.[122] This means that the total surcharge revenue collected by the utility is approximately 40% of all revenues, and fuel revenues are 27% of all revenues. Fuel revenues are not collected through base rates, are highly volatile and are largely outside of the Company's control. With fuel being a significant component of the total class revenue, it is unreasonable to include these fuel revenues in the class total revenue amount when determining the appropriate spread of the requested revenue increase across classes under the gradualism constraints.

FPL's own MFR Schedule E-13a shows the inequitable results of its proposed application of the gradualism constraints, where more than half of the rate classes will receive more than 1.5 times the system average increase in base rate revenues. The two sub-classes of customers receiving the largest base rate increases are the CILC-1D sub-class (57% increase) and the CILC-1T sub-class (78% increase), whereas the system average increase in base rates is only 15.8%. The CILC class will receive these egregiously inequitable rate increases due to the compounding effects of FPL's inappropriate application of the gradualism constraints and FPL's proposal to

[121]MFR No. E-14, Attachment 2 of 6, page 31 of 42.

[122]FPL's Response to OPC's First Request for Production of Documents, No. 1, "Clauses for E-8 based on NOI for E-8 Clause Revenues.xlsm".

reduce the current level of the CILC/CDR Interruptible Credits by $23 million. FPL has not taken into account the additional $23 million in revenues it seeks to collect from CILC/CDR customers due to the reduction in the Interruptible Credits when applying the gradualism constraints to determine proposed base rates for all customers.[123] The result is that, if FPL's revenue spread proposals are approved, CILC-1D and CILC-1T customers will receive an increase that is 3.6 times and 4.9 times, respectively, the system average base rate increase.

Applying the gradualism constraints proposed by FPL, the 1.5 times system average maximum and no rate decrease as a minimum, to non-fuel revenues is not atypical in the industry. Electric utilities that operate in deregulated markets provide only distribution service to customers, and therefore the fuel and production-related revenue is collected by generating companies and not a part of ratemaking for the distribution-only utilities.

FEA proposes the 1.5 times gradualism constraint be applied to total class revenues excluding the fuel surcharge revenue when determining the appropriate revenue increase spread across customer classes. Application of the gradualism constraints in this way will not unduly burden any class or sub-class of customers.

## RATE DESIGN – RATE CILC

**STATEMENT OF POSITION:**

**ISSUE 150: What are the appropriate charges for the Commercial Industrial Load Control (CILC) rate schedule**

**A. Effective January 1, 2017?**

**FEA:** Using the Company's proposed revenue requirement and the 12 CP and 1/13th allocation method for example, the following rates should apply:

[123]See footnote on MFR Schedule E-13a, page 1 of 1.

| | CILC-1G | CILC-1D | CILC-1T |
|---|---|---|---|
| | below 69 kV | | >69 kV |
| | 200-499 kW | 500 kW+ | |
| Load Control Dmd | $1.20 | $1.20 | $1.20 |
| Firm Demand | $7.96 | $7.52 | $7.50 |
| Max (Dist.) Dmd | $4.54 | $4.21 | n/a |
| Energy | 1.813 | 1.476 | 1.311 |

The rate design should reflect the final authorized revenue requirement and cost of service methodologies, and should follow the CILC rate design process used in FPL's last base rate case, described in Docket No. 120015-EI, Ms. Deaton's Exhibit RBD-6, beginning at page 13.

**B. Effective January 1, 2018?**

**FEA:** Rates should reflect the final authorized revenue requirement and cost of service methodologies, and should follow the CILC rate design process used in FPL's last base rate case, described in Docket No. 120015-EI, Ms. Deaton's Exhibit RBD-6, beginning at page 13.

**DISCUSSION:**

FEA finds the Company's proposed CILC rate charges to be illogical and not reflective of the cost to serve these customers. Further, the Company's proposed modification to its CILC rate design is so economically illogical that it will create strong economic incentives for customers to migrate between rate schedules simply to lower their cost of service. If the CILC rate continues to be structured in an economically logical manner, as is the current CILC rate design, then this incentive for rate migration will be eliminated. FEA proposes that the current economically logical design of the CILC rate class be continued, and adjustments to these rates be made only to reflect changes in the allocated cost of service to this rate schedule.

**1. Illogical Rates vis-à-vis Cost of Service**

Table 5 below provides a comparison of the CILC rate charges under FPL's current tariff, and under proposed FPL's proposed tariff, to illustrate the illogical results.

**TABLE 5**

**Present and Proposed CILC Base Rate Charges**
(Demand Charges $/kW, Energy Charges ¢/kWh)

| | Present Rates | | | Company's 2017 Proposed Rates | | |
|---|---|---|---|---|---|---|
| | CILC-1G | CILC-1D | CILC-1T | CILC-1G | CILC-1D | CILC-1T |
| | below 69 kV | | >69 kV | below 69 kV | | >69 kV |
| | 200-499 kW | 500 kW+ | | 200-499 kW | 500 kW+ | |
| Load Control Dmd | $1.97 | $1.97 | $1.97 | $3.30 | $4.00 | $4.40 |
| Firm Demand | $8.73 | $8.51 | $8.65 | $12.00 | $14.20 | $16.40 |
| Max (Dist.) Dmd | $3.82 | $3.49 | n/a | $4.90 | $5.50 | n/a |
| Energy | 1.425 | 0.822 | 0.731 | 1.828 | 1.272 | 1.307 |

As shown in Table 5 above, the existing CILC rate design reflects a declining charge for generation and transmission service, and for energy consumption, for CILC customers that take service at a higher delivery voltage level. The current CILC rate design is economically logical because FPL costs are lower for customers served at higher voltages. High voltage customers are lower cost to serve because they cause fewer energy and demand losses on the system than do lower voltage customers. FPL's existing rate structure for the CILC class, also shown in Table 5 above, reflects the reduction in losses through declining rates based on delivery voltage service.

In significant contrast, the proposed rates reflect a higher charge for transmission (higher) voltage level service than they do for primary and secondary (lower) voltage customers. In stark contrast to FPL's existing CILC rate design, the proposed new rate design is economically illogical. The Company holds less generation capacity per unit of demand to serve a transmission voltage level customer than it would need for primary and secondary voltage customers, because of the difference in losses.

Further, customers who take service at transmission voltage levels do not make use of the distribution system at lower (primary and secondary) voltage levels, therefore the distribution demand charges should be lower for a transmission voltage customer. FPL's current CILC rates correctly charge a lower distribution charge for transmission voltage customers than for primary and secondary voltage customers, but FPL's proposed CILC rates charge a higher distribution demand rate for the transmission voltage charges. Again, FPL's proposed rates are contrary to cost of service.

There is no dispute that FPL incurs greater costs to serve customers at lower voltages. FPL admitted in cross-examination that customers who take service at transmission level cause less energy and demand losses on the system than primary and secondary voltage level customers.[124] FPL admitted in rebuttal testimony that the unit costs for distribution, transmission, and energy service for CILC customers in FPL's cost of service study prove that the costs to provide distribution, transmission, and energy service to CILC transmission voltage customers is less than the cost to provide those services to CILC primary and secondary voltage customers.[125] But FPL goes on in testimony[126] to argue that the gradualism constraints allow FPL to assign a greater share of the revenue increase to CILC transmission voltage customers, essentially setting tariff rate charges based on "what the market will bear" as opposed to following the true cost to provide electric service. FPL's gradualism adjustment will create illogical price signals to CILC customers of all delivery voltage levels, and will create uneconomic incentives for CILC customers to migrate between CILC rates to choose the lowest cost rate.[127] The change in the CILC rate design that creates these uneconomic incentives to migrate rates should be rejected. Instead, the existing economically logical structure of the CILC rate should be preserved.

[124]Transcript, cross of FPL witness Cohen, page 5335, lines 15-21.
[125]Rebuttal Testimony of FPL witness Cohen, page 17, line 22 – page 18, line 1.
[126]*Id.*, page 18, lines 2-7.
[127]Transcript, cross of FEA witness Alderson, page 3816, lines 19-22.

## 2. Proposed CILC Rate Design is Not a Refinement

FPL argues that its process for designing rates in the instant proceeding is "consistent with FPL's proposals in past rate cases; however, FPL refined the process."[128] This is a misleading characterization of the facts. Evidence[129] has been presented identifying the clear departure from FPL's past method of designing rates, which were appropriately based on the cost to serve the various voltage level customers within the CILC rate, and produced tariff rates that were logical and provided efficient pricing signals to customers. In both of FPL's last two base rate cases, Dockets No. 120015-EI and 080677-EI, FPL witness Deaton sponsored nearly identical passages in her Direct Testimony describing the development of the CILC rate charges, where transmission rates are based on the transmission unit costs from FPL's cost of service study, production rates based on the production unit costs, and distribution rates based on distribution unit costs as developed for the individual voltage rate sub-groups in FPL's cost of service study. In the instant proceeding, FPL witness Cohen includes no such detailed passage in testimony concerning rate design, but describes the FPL's new rate design process in a single sentence, "Proposed demand and energy charges were calculated by applying the rate class increase percentage to current rates."[130] Because FPL's new rate design process produces rates that are illogical between the voltage level sub-classes, FEA recommends the Commission instruct FPL to design CILC rates using the method approved in FPL's last two base rate cases.

FPL argues that its new process is superior to its old rate design process because it "mitigates the impact of rate increases on low load factor customers."[131] But FPL's old rate design

[128]Rebuttal Testimony of FPL witness Cohen, page 14, lines 7-8.

[129]Hearing Exhibits 779-780; Direct Testimony of FEA witness Alderson, page 33, line 12 – page 34, line 8.

[130]Direct Testimony of FPL witness Cohen, Exhibit TCC-6, page 16, line 22 – page 17, line 1.

[131]Rebuttal Testimony of FPL witness Cohen, page 15, lines 2-3.

process sufficiently mitigates the impact of rate increases on low load factor customers as well, as evidenced by FPL's own testimony in this proceeding, where Ms. Cohen states, "In prior cases, FPL started with demand unit cost and adjusted them down to maintain the same relationship between demand and energy changes [sic] and to **mitigate the impact to low load factor customers**."[132]

FPL's proposed new method for developing CILC base rate charges results in higher charges for transmission voltage level customers than for primary and secondary voltage level customers. The undisputed reality is that it is cheaper to serve a transmission voltage level customer than a primary or secondary voltage level customer. FPL's proposed prices, being illogical and opposite of cost of service, will result in rate migration between classes, where a transmission voltage level customer will find it cheaper to take service under the primary or secondary voltage rate. Unless FPL's tariff rules and regulations prevent transmission voltage customers from migrating to a lower voltage rate, FPL will recover less revenue from CILC transmission voltage customers when they request a tariff rate change to the lower voltage rate. This sending inefficient pricing signals to customers promotes inefficient use of the FPL system, signaling to transmission voltage level customers that they are more costly to serve than lower voltage customers, and therefore customers are incentivized to begin taking service at a lower voltage, which in reality is more costly to serve than transmission voltage customers. Especially in this proceeding where FPL is requesting a four-year rate plan, and the CILC base rate charge design would not be revisited for at least four years, the results of rate migration could be significant.

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[132]*Id.*, page 14, lines 10-13, emphasis added.

The Commission should direct FPL to preserve its existing economically rational design of the CILC rate. FPL's existing CILC rate design appropriately reflects costs of service, and will not create uneconomic price signals for CILC customers to migrate across rate schedules to a lower cost rate.

## <u>CILC Interruptible Credits</u>

**STATEMENT OF POSITION:**

**<u>ISSUE 145</u>: What is the appropriate monthly credit for Commercial/Industrial Demand Reduction (CDR) Rider customers effective January 1, 2017?**

**<u>FEA</u>:** The credit level should remain unchanged from current tariff rates. FPL's proposal to reduce the credit level should be rejected.

**DISCUSSION:**

FPL is requesting in this proceeding to reduce by $23 million (37%) the value of CILC and CDR customers' interruptibility. These customers are given a rate credit for the load that they have offered to the Company as non-firm through the CDR Rider, or through the differential between the CILC base rate charges and the otherwise applicable General Service rate charges for firm service. But FPL has provided no analysis in this proceeding to support the reasonableness of its proposal, presumably because FPL continually claims that the proper venue for determining the appropriate level of CILC/CDR credits is in FPL's Demand Side Management ("DSM") proceedings, which are held periodically before the Commission to consider the continuance of all of FPL's demand side management programs.[133] Further, FPL has admitted that the CILC customers' interruptible load does not count toward FPL's DSM goals.[134] Whether the appropriate

[133]Transcript, cross of FPL witness Cohen, page 5329, line 25 – page 5330, line 5; Transcript, cross of FPL witness Koch, page 5360, lines 13-16; and Rebuttal Testimony of FPL witness Cohen, page 23, lines 8-10, citing Ms. Deaton's testimony in the 2012 rate case, Docket No. 120015-EI.

[134]Rebuttal Testimony of FPL witness Koch, page 6, lines 1-2.

venue to set CILC interruptible credits is in a base rate proceeding or a DSM proceeding is an open question, but the fact remains that FPL has not provided sufficient evidence in the instant base rate proceeding to justify changing the CILC/CDR interruptible credit levels.

The interruptible credit level under FPL's current tariff rates is approximately $6.17/kW-month,[135] and FPL proposes a reduction of approximately 37%, which would result in a credit of only $3.89/kW-month. To evaluate the reasonableness of FPL's proposal, one should consider the value that CILC customers provide to FPL when they interrupt load. Determining the value of this load resource to FPL is different than determining the "amount sufficient to obtain the participation needed from a given program to provide its projected contribution towards the DSM Goals,"[136] which is how FPL witness Koch explains the credits are set in a DSM proceeding. The quoted analysis process essentially determines "what the market will bear", or how low the interruptible credits can be set where customers will still provide interruptible load, which is similar to determining how expensive an item can be sold for on the market where customers will still buy the item, without regard to how much the item truly costs to produce. In the case here, FPL is not producing the item in question, the interruptible load, but rather FPL's own customers are agreeing to reduce load in order to free up generating capacity for use in serving other customers. Therefore, the interruptible credit paid to the CILC and CDR customers should be tied to the cost FPL is avoiding by not needing to install new capacity to serve customers.

FEA has provided an analysis in testimony to determine the true value of the CILC and CDR customers' interruptible load to FPL, and finds the current interruptible credit levels and FPL's proposed levels to be both far below the actual value to FPL (approximately $8.45/kW-

[135]Direct Testimony of FEA witness Alderson, page 29, lines 1-5.
[136]Rebuttal Testimony of FPL witness Koch, page 5, lines 15-17.

mo.).[137] Therefore the Commission should find FPL's proposal to reduce the current CILC/CDR credit levels by 37% to be unreasonable, as they would be therefore priced significantly below the true value of the interruptible load, and the 37% reduction has not been supported by any analysis in this proceeding.

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[137] Direct Testimony of FEA witness Alderson, page 28, lines 16-26.

**CERTIFICATE OF SERVICE**
**Docket No. 160021**

**I HEREBY CERTIFY** that a true and correct copy of the foregoing Federal Executive Agencies' Post-Hearing Brief has been furnished by electronic mail (e-mail) and/or U.S. Mail this 19th day of September, 2016 to the following:

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