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August 10, 2017

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20170057-EI

Dear Ms. Stauffer,

Please find enclosed for filing in the above referenced docket the Direct Testimony and Exhibits of **Daniel J. Lawton**. This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

If you have any questions or concerns; please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Erik L. Sayler
Associate Public Counsel

ELS:bsr
cc: All Parties of Record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Analysis of IOU's Hedging Practices	§ § § § § § § § § § §	Docket No. 20170057-EI Filed: August 10, 2017

DIRECT TESTIMONY AND EXHIBITS

OF

DANIEL J. LAWTON

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

August 10, 2017

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Exhibits

DIRECT TESTIMONY

OF

DANIEL J. LAWTON

On Behalf of the Office of Public Counsel

Before the

Florida Public Service commission

Docket No. 20170057-EI

SECTION I: <u>INTRODUCTION / BACKGROUND / SUMMARY</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 12600 Hill Country Blvd, Suite R-275, Austin, Texas 78738.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. Consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, financial analyses, revenue requirements, fuel cost reviews, cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities, and in court proceedings. I have worked with numerous municipal utilities developing electric rate cost of service studies for reviewing and setting rates, including fuel recovery clauses and fuel cost reconciliation. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas rate proceedings and other litigation and contract matters. I have included a brief description of my relevant educational background and professional work experience in my Exhibit___DJL-1.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN UTILITY RATE PROCEEDINGS?

A. Yes. I have previously filed testimony in Florida and a number of other jurisdictions across the country. A list of cases in which I have previously filed testimony is included in my Exhibit ___ DJL-1.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY RELATED TO FINANCIAL HEDGING PRACTICES?

A. Yes. Please see my testimony and exhibits filed in Docket Nos. 20150001-EI and 20160001-EI.

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I am providing analyses and testimony related to financial hedging on behalf of the Office of Public Counsel, State of Florida ("OPC"). I will review the Florida Power & Light Company ("FPL"), Tampa Electric Company ("TECO"), and Duke Energy Florida ("DEF) collectively ("the Companies") financial hedging proposals and testimony related to fuel cost recovery.[1]

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[1] Gulf Power Company ("Gulf") also employs financial hedging, but is not part of this proceeding. I will address some historical data that does include Gulf's past hedging practices.

Q. WHAT ISSUES ARE BEFORE THE COMMISSION IN THIS PROCEEDING?

A. The purpose of this proceeding is to analyze the Companies' financial hedging practices. Specifically, the first issue to be addressed is whether the Companies should continue financial hedging as a mechanism to limit fuel price volatility. If the Commission determines that financial hedging should be discontinued, then the inquiry into the Companies' financial hedging practices should end. However, if the Commission determines that the Companies should continue financial hedging, then the Commission needs to decide the type of hedging program that should be employed. In this case, there are three natural gas financial hedging programs before the Commission: (1) the current financial hedging program (currently suspended), (2) the Companies' proposed alternative to the current financial hedging program (Out-of-the-money ("OTM") call options program), and (3) the risk-responsive hedging program sponsored by Staff's Consultant Michael Gettings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to address whether financial hedging by the Florida Companies should continue. I will also address issues or problems with the various financial hedging proposals that are before the Commission in this case. I provide a general historical review of the financial hedging programs in Florida. I also provide a review of the current state of natural gas markets and the need for financial hedging. In addition, I address why financial hedging should be discontinued, as past hedging has been unnecessarily costly to customers of the Florida Companies. I also address the various problems with the proposed alternative hedging programs before the Commission.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. I have reviewed prior rate orders of the Commission, the Companies' various filings in Docket No. 20170057-EI, the Companies' filings in prior dockets, discovery responses to requests in this proceeding, along with other information available in the public domain. When relying on various sources, I have referenced such sources in my testimony and/or attached Exhibits and included copies or summaries in my attached Exhibits and/or work papers.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE REASONABLENESS OF CONTINUED FINANCIAL HEDGING.

A. My analysis leads me to conclude that the overall costs of the current natural gas financial hedging programs as described in the Companies' prior Risk Management Plans continue to exceed the benefits to consumers. Financial hedging costs to Florida consumers continue to mount, now approximately $6.7 billion for the period 2002-2016, while hedging benefits (reduced volatility) to customers appear minimal at best. On the other hand, the current hedging programs in Florida continue to provide benefits for the utility shareholders in terms of reduced liquidity risk, but at the expense of increased consumer fuel costs. As discussed in my testimony in Docket No. 20150001-EI,[2] utility companies around the country continue to reduce financial hedging activities in light of the substantial changes and increased stability in the natural gas markets. There are alternatives available to establish the fuel factor and to recognize gas market

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[2] Document No. 06001-2015, Direct testimony of Daniel J. Lawton and Exhs DJL-1 through DJL-9, Filed September 23, 2015, in Docket No. 20160001-EI.

price changes without the added risk of enormous and continued hedging losses. Therefore, I recommend that, on a prospective basis, the Commission should end natural gas financial hedging activities as a mechanism to limit (fuel) price volatility.

However, if the Commission determines that financial hedging should continue, the following three issues related to financial hedging should be considered. First, the problems and costs with the Companies' current financial hedging programs that have been in place since 2002. Second, the Companies' alternative financial hedging proposal of purchasing OTM call options. Third the problems associated with the risk responsive financial hedging approach proposed by Mr. Gettings.

The following are reasons why I recommend that the current hedging program should be ended:

1. There is significant doubt as to the benefits of natural gas financial hedging given the continued low prices and stable production and demand forces in natural gas markets, versus the historical, ongoing, and potential future financial hedging costs to consumers;
2. Natural gas markets in terms of gas production and market supply have changed substantially in recent years, reducing the probability and extent of significant supply-side market disruptions and also reducing natural gas price volatility relative to past years;

3. Regulatory authorities around the country are recognizing the limitations of financial hedging in the changed natural gas markets;

4. The current fuel factor design and mid-course correction mechanism utilized in Florida already mitigate fuel cost volatility without the need and cost risk of financial hedging; and

5. All of the above factors weigh strongly against the need or usefulness of a financial hedging program for natural gas purchases.

If the Commission determines that some alternative natural gas financial hedging should be employed, then I recommend the following:

1. The Companies' proposed OTM call options alternative be rejected as such a program is too costly to consumers as opposed to any potential benefits;

2. Mr. Gettings' risk-responsive financial hedging proposal should also be rejected as such a program will likely lead to more uncertainty, more litigation, and potentially more costs; and

3. The Commission extend the current financial hedging moratorium period, suspending all financial hedging programs consistent with the FPL and Gulf settlement agreements in order for the Commission and applicable parties to evaluate the need and type, if any, of financial hedging that may be required in Florida in the future. At the end of the moratorium, the Commission may then

order implementation of the most efficient volatility mitigation program, if any is needed, to address fuel volatility for Florida consumers, which may or may not include financial hedging.

SECTION II: <u>CHANGES IN NATURAL GAS MARKETS</u>

Q. PLEASE ADDRESS THE ISSUES AND EVIDENCE REGARDING THE CHANGES IN NATURAL GAS MARKETS?

A. Exhibit___DJL-2 contains a graph of monthly average natural gas prices from the Henry Hub for the period January 1997 through June 2017. In addition, I have included several summary statistics regarding the minimum, maximum, average and standard deviation over this twenty-year period. I have broken down the 20-year historical period and included similar historical graphs of natural gas prices and summary statistics in Exhibits___DJL-3 through DJL-6 for the periods (January 1997-December 2008), (January 2009-June 2017), (January 2014-June 2017), and (January 2015-June 2017) respectively. These historical reviews are summarized in the following table:

TABLE 1

HISTORICAL SUMMARY STATISTICS OF NATURAL GAS PRICES

METRIC	**1/1997 – 12/2008**	**1/2009 – 6/2017**	**1/2014 – 6/2017**	**1/2015 – 6/2017**
MAXIMUM PRICE	**$13.42**	**$6.00**	**$6.00**	**$3.59**
MINIMUM PRICE	**$1.72**	**$1.73**	**$1.73**	**$1.73**
AVERAGE PRICE	**$5.11**	**$3.51**	**$3.16**	**$2.67**
STANDARD DEVIATION	**$2.64**	**$0.89**	**$0.93**	**$0.45**

As shown in Table 1, the period 1997–2008 has the highest average gas price and the highest level of volatility as measured by the standard deviation over the historical period. The 2009–2017 period is the post-financial recession period and also represents a period where shale production investment and natural gas production had a substantial impact on gas markets. During this period, there is a dramatic drop in average gas price to $3.51/per Mcf and the volatility measure declined three-fold to $0.89.

In addition, there is a dramatic difference in average price levels and price volatility between the 1997-2008 period and the January 2009-June 2017 period. Natural gas markets have changed dramatically from early 2000 when financial hedging was first employed in Florida to address price volatility experienced in the early 2000 period. The more recent period of January 2015-June 2017 shows average price per Mcf declining and volatility continues to be well below the levels from the 1997 through 2008 period. Lastly, the more recent two and one-half year period of January 2015-June 2017 shows the continuing decline in average price and declining standard deviation of gas price (volatility) from prior periods. The most recent period's standard deviation of $0.45 is approximately 5.9 times lower than the $2.64 standard deviation in the 1997-2008 period.

Evaluation of this historical data demonstrates gas markets and prices have become more stable since the early 2000 period when natural gas hedging was initially evaluated and adopted as a mechanism to protect consumers. Moreover, current Energy Information Administration ("EIA") forecasts show that gas market supply and demand continue to grow through 2050 and prices to be relatively stable throughout the forecast period.[3]

Q. WHAT FACTORS CAUSE PRICE CHANGES IN NATURAL GAS MARKETS?

A. In the short run, weather is a major factor influencing natural gas demand and prices. Given the current robust natural gas market supply and storage availability, weather impacts are less pronounced in current versus past periods. Another short-run factor is infrastructure or pipeline deliverability. To the extent there is insufficient deliverability or a disruption in deliverability, such infrastructure shortfall can have a short-run impact on market price. In the longer run, deliverability and infrastructure issues can be resolved with increased pipeline investment.

An example of a weather/infrastructure impact on natural gas prices occurred in late February through early March 2014 when the so-called Polar Vortex temporarily impacted natural gas prices. Extreme cold in the northern part of the country increased natural gas demand for both heating and electric generation, and pipeline constraints limited the deliverability of natural gas in eastern New York and New England. Pipeline expansions in 2015 and 2016 have addressed these infrastructure issues.

It is important to note that infrastructure changes are also improving the Florida market deliverability. For example, in July 2017, the Federal Energy Regulatory Commission

[3] U.S. Energy Information Administration, Annual Energy Outlook 2017 with projections to 2050, available at https://www.eia.gov/outlooks/aeo/

("FERC") authorized Phase 1 of the Sabal Trail pipeline to begin full operation.[4] Such pipeline additions increase infrastructure pipeline capacity as Florida increases gas generation. The Sabal Trail pipeline project will eventually include a Central Florida Hub ("CFH") that will connect the Sabal Trail pipeline to the existing Gulfstream and FGT systems, as well as to the Florida Southeast Connection. According to Order PSC-13-0505-PAA-EI: "The CFH will include facilities needed to provide hub wheeling services to deliver contracted capacities interchangeably between and among each of the pipelines, which further increases the flexibility and possible diversity for all the gas shippers in the area."[5] Once the CFH is constructed and the other pipelines are interconnected, it should provide increased supply reliability and backhaul capability in the event of a supply interruption caused by a pipeline outage on Gulfstream or FGT.

Q. DO CURRENT MARKET FORECASTS INDICATE A STABLE NATURAL GAS MARKET FOR THE FUTURE?

A. Yes, they do. The long-term 2017 EIA forecast through 2050 ("Annual Energy Outlook 2017") projects in the base or reference case that the U.S. benchmark Henry Hub spot prices will increase modestly between 2020 and 2030 and stay relatively flat after 2030.[6]

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[4] U.S. Energy Information Administration, Today In Energy at 1 (July 10, 2017), available at www.eia.gov/todayinenergy

[5] Order PSC-13-0505-PAA-EI, Issued October 28, 2013, in Docket No. 20130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company at 14.

[6] U.S. Energy Information Administration, Annual Energy Outlook 2017 at 56, available at https://www.eia.gov/outlooks/aeo/

Q. IS EIA'S CURRENT LONG-TERM NATURAL GAS MARKET FORECAST CONSISTENT WITH RECENT LONG-TERM FORECASTS?

A. Yes, it is. Last year's 2016 EIA long-term forecast through 2040 shows a stable supply and demand in natural gas markets. The projections of real price change indicate a 2.5% growth in prices for natural gas over the long-term horizon. One of the key takeaways from the 2016 long-term forecast is that "[n]atural gas production increases despite relatively low and stable gas prices."[7] The bottom line is that the U.S. is expected to be a net exporter of natural gas. The amount of exports will be influenced by foreign prices for natural gas. Domestic production is also expected to increase with domestic prices remaining low and stable. Price volatility is not expected to be an issue, meaning financial hedging will provide less benefits, if any benefit at all, based on current EIA forecasts.

Q. DURING THE RECENT PERIOD OF LOW, STEADY GAS PRICES AND STABLE MARKET CONDITIONS, HAVE FLORIDA CONSUMERS CONTINUED TO PAY SUBSTANTIAL COSTS RESULTING FROM THE FLORIDA UTILITIES' FINANCIAL HEDGING PROGRAMS?

A. Yes. The Companies' historical cumulative level of financial hedging losses for the period 2002-2016 amounts to approximately $6.7 billion. I outline the annual financial hedging losses by utility by year in the following table.

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[7] See U.S. EIA Annual Energy Outlook, Key takeaways from AEO 2016 at 2, available at www.eia.gov/pressroom/presentations/sieminski_06282016.pdf.

TABLE 2

2002 – 2016 HISTORICAL AND ESTIMATED 2017 FINANCIAL HEDGING LOSSES IN FLORIDA

YEAR	DEF HEDGING[8] SAVINGS (COST)	TECO HEDGING [9]SAVINGS (COST)	FPL HEDGING SAVINGS (COST)[10]	CUMULATIVE HEDGING SAVINGS (COST)
2002	$0	($203,500)	$14,520,306	$14,316,806
2003	$0	($2,758,028)	($15,939,810)	($18,697,838)
2004	$0	$8,413,170	$191,564,536	$199,977,706
2005	$0	$53,231,770	$519,388,788	$572,620,558
2006	($17,808,320)	($54,482,120)	($416,637,197)	($488,927,637)
2007	($65,422,064)	($59,691,520)	($799,268,428)	($924,382,012)
2008	$58,551,704	$18,147,375	$100,709,736	$177,408,815
2009	($552,297,855)	($193,185,985)	($1,660,695,829)	($2,406,179,669)
2010	($282,079,398)	($67,840,710)	($509,147,046)	($859,067,154)
2011	($239,721,035)	($33,889,480)	($404,239,340)	($677,849,855)
2012	($351,321,610)	($61,518,120)	($671,819,795)	($1,084,659,525)
2013	($140,907,108)	($3,256,370)	$18,253,045	($125,910,433)
2014	($27,741,075)	$15,615,785	$116,639,265	$104,513,975
2015	($225,543,645)	($39,842,325)	($493,138,120)	($758,524,090)
2016	($150,182,975)	($19,333,375)	($223,649,160)	($393,165,510)
TOTAL HISTORICAL	($1,994,473,381)	($440,593,433)	($4,233,459,049)	($6,668,525,863)
2017 ESTIMATED	($25,000,000)	$3,789,815	$51,430,824	$30,220,639
TOTAL ALL	($2,019,473,381)	($436,803,618)	($4,182,028,225)	($6,638,305,224)

The Companies have had substantial hedging losses when prices were increasing, decreasing, and even remaining stable. More importantly, the Companies' financial hedging programs have been costly to Florida consumers and show no signs of improvement for the future. Therefore, these programs should be discontinued. The costs of financial hedging to consumers exceed any benefits of reduced price volatility,

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[8] See DEF's response to OPC Interrogatory No. 1, dated June 23, 2017, shows DEF's cumulative natural gas financial hedging savings (costs). Prior to 2006, DEF did not financially hedge natural gas; therefore, DEF did not have any financial hedging savings (costs) for years 2002 to 2005. DEF's supplemental response to OPC Interrogatory No. 1, dated August 7, 2017, shows the net savings (costs) of DEF's physical and financial hedging programs for the period.

[9] See TECO's response to OPC Interrogatory No. 1, dated June 23, 2017.

[10] See FPL's response to OPC Interrogatory No. 1, dated June 23, 2017.

which is especially true when recent and projected gas markets have become stable with much lower volatility.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS REGARDING CHANGES IN THE NATURAL GAS MARKETS AND THE NEED FOR FINANCIAL HEDGING?

A. Since the time natural gas hedging and risk management for fuel procurement was first formally implemented in Florida in 2002[11] to address natural gas price volatility, annual gas production has grown dramatically and available gas reserves are well beyond forecasted levels from even ten years ago. As a result, price levels have declined substantially and price volatility is substantially reduced from past levels. As I discussed earlier, over that same period, the Companies have continued to generate substantial financial hedging losses, which are passed on to consumers in the form of higher fuel costs. Since January 2015, the Companies' hedging programs have sustained over $1.15 billion in hedging losses (see Table 2) at a time when prices and price volatility lave been low and stable (see Exhibit___DJL-6). These losses ultimately flow through to customers in the form of higher bills; thus, financial hedging has not protected Florida consumers.

Moreover, current forecasts of market prices indicate stable gas prices in the near-term, mid-term, and longer-term time horizons. Current market forecasts for natural gas all indicate that natural gas prices and markets are more stable, and the facts and

[11] Order No. PSC-02-1484-FOF-EI (Order approving proposed resolution of issues), issued October 30, 2002, in Docket No. 20011605-EI, In re: Review of Investor-owned electric utilities' risk management policies and procedures.

circumstances that once supported natural gas hedging as a tool to limit price volatility are no longer present. Further, there are available, transparent, cost-free opportunities to limit price volatility impacts while factoring in future expectations in the gas market prices through the Commission's fuel adjustment clause without financial hedging. Given the enormous lost-opportunity costs experienced by consumers in terms of overall fuel costs, plus the potential for additional lost opportunities for lower gas costs, the financial hedging of natural gas should be ended at this time.

For all the above reasons, I recommend that the Commission end financial hedging of natural gas.

SECTION III: <u>FINANCIAL HEDGING ALTERNATIVES</u>

Q. PLEASE ADDRESS THE FINANCIAL HEDGING PROPOSALS BEING PRESENTED IN THIS CASE.

A. There are three financial hedging proposals before the Commission in this case: (1) the status quo hedging methodology ("Targeted-Volume Hedging Approach"); (2) the Companies' "Out-of-the-Money" call option ("OTM") financial hedging proposal; and (3) Mr. Gettings' "Risk-Responsive" financial hedging proposal. There is also a fourth proposal, discussed later herein, which simply entails a hiatus of financial hedging.

Targeted-Volume Financial Hedging

The current financial hedging method employed by the Companies is what is commonly referred to as fixed-ratio hedging, also known as targeted-volume financial hedging. Under the targeted-volume approach, as part of their Risk Management Plans for fuel procurement, the Companies each year determine a specific percentage of gas purchases or targeted volumes of gas purchases that will be hedged. This fixed percentage of gas is subject to a fixed locked-in price and, as such, is not subject to market price changes up or down. The problem with the targeted-volume hedging approach is that the volume to hedge does not consider changing market factors, changing market prices or even changing volatility. Instead, a percentage of forecasted gas purchases have prices locked-in through hedging contracts to assure no price movement (volatility) for the locked-in gas percentage.

Thus, the issues presented with the current hedging method is that when hedged prices are locked-in at high levels and market prices decline, the consumers are required to pay the hedged higher prices and do not enjoy the lower market gas prices on the volume of gas purchases that were previously hedged. This becomes a significant problem in a declining price market that has occurred over a number of years as is evidenced in Exhibit___DJL-2 and Table 2 above. As a result, the Companies' targeted volume hedging approach has cost consumers billions of dollars[12] in higher fuel costs to date, and these losses continue to mount year after year.

In this proceeding, it is important to note that all of the Companies have proposed to abandon the targeted-volume financial hedging approach in favor of OTM call option hedging.[13] Given that none of the parties in this proceeding, including Mr. Gettings,

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[12] See Table 2.

[13] Document No. 05680-2017, filed July 3, 2017, in Docket No. 20170057-EI, Direct Testimony FPL witness Yupp page 5, line 9; Document No. 05682-2017, Direct Testimony DEF witness McCallister page 2, lines 20 – 21; Document No. 05677-2017, Direct Testimony TECO witness Caldwell page 12, line 20.

the Staff's consultant, support the failed and costly current hedging approach, there is effectively a consensus for the Commission to discontinue this failed fixed percentage or targeted-volume financial hedging experiment in Florida.

Out-Of-The-Money ("OTM") Call Options

Q. PLEASE ADDRESS THE COMPANIES' OTM CALL OPTION PROPOSAL.

A. The Companies' collective testimony in this proceeding have proposed that the Commission approve the OTM call option approach in lieu of either the status quo Targeted-Volume Hedging Approach or Mr. Gettings' risk-responsive hedging proposal.[14] Under the OTM call option alternative, any of the Companies can purchase an instrument that allows the holder the option (but not the obligation) to purchase a specified quantity of natural gas at a specific date and at a specific price.

The following is an example of how a call option works. A utility could purchase a call option today for the right to purchase a quantity of natural gas at a strike price of \$4.00 per MMBtu in October 2017. The price of that option is called a premium. If the natural gas price in October 2017 turns out to be \$4.50 per MMBtu, the call option would be exercised, resulting in a financial settlement in which the utility receives \$0.50 per MMBtu (\$4.50 October market price less the \$4.00 call option price). The \$0.50 per MMBtu settlement will then be used to offset customer fuel costs. Thus, the transaction result is as if the utility purchased a quantity of natural gas at \$4.00 per MMBtu rather than the \$4.50 MMBtu market price. However, the cost of the call option (or premium) would also be factored into the overall price of the natural gas

[14] Id.

borne by the utility's ratepayers. On the other hand, if the natural gas price in October 2017 is $3.50 per MMBtu, then the option would not be exercised and it would be allowed to expire. Natural gas will be purchased for consumers at the lower $3.50 per MMBtu. In that instance, while consumers get the benefit of the lower $3.50 per MMBtu gas costs, customers still must pay the call option cost or premium purchased by the utility.

All call options, which allow the holder to purchase natural gas at a specified date and cost, require the payment of a premium. As noted by FPL witness Yupp, these call option premiums "… can be substantial if the market is highly volatile."[15] Therefore, when call options are needed the most, i.e., in volatile markets, call option premiums or costs are at their highest levels.

To address this issue of high cost call options, the Companies are proposing to employ out-of-the-money call options which are options with strike prices higher than the forecasted market price of natural gas. The OTM call option premium is much lower if the option purchaser is willing to purchase an option where the strike price is higher than the estimate of future market price. Using the example discussed above, where the expected future price was $4.00 per MMBtu, if the purchaser is willing to buy the call option with a strike price of $4.50 per MMBtu rather than the expected October price of $4.00 per MMBtu, this is an out-of-the-money purchase. The cost of such an option would be substantially less than the October 2017 option with a $4.00 strike

[15] Document No. 05680-2017, filed July 3, 2017, in Docket No. 20170057-EI, Direct Testimony FPL witness Yupp at page 10, lines 16 – 18.

price. However, if gas prices suddenly spiked to a level above $4.50 per MMBtu, the out-of-the-money option would now be in-the-money and exercised, and the Companies would be reimbursed for the cost of natural gas above $4.50 per MMBtu. FPL, Duke, and TECO have collectively put the OTM call option approach forward as a lower cost alternative to both the current targeted-volume financial hedging program and to Mr. Gettings' risk responsive financial hedging proposal.

Q. WHAT ARE THE ESTIMATED CONSUMER COST IMPACTS OF THE COMPANIES' PROPOSED OTM CALL OPTION HEDGING ALTERNATIVE?

A. Mr. Yupp of FPL has estimated the impact of OTM call options versus the risk responsive approach and relative to the market in his Exhibit GJY-2.[16] Using Mr. Yupp's data, I was able to estimate the customer cost of OTM call options versus *no hedging* (i.e., paying market prices over the 2007 to 2016 period) at approximately $888 million.[17] I also estimate that the cost of OTM call option proposal relative to Mr. Gettings' risk responsive approach is less costly over the 2007 to 2016 measurement period by approximately $994 million.[18]

These estimates indicate that OTM call option proposal is lower cost than the current financial hedging method and the risk responsive method presented by Mr. Gettings. However, these estimates also indicate that the OTM call options are substantially more

[16] See Document No. 05680-2017, filed July 3, 2017, in Docket No. 20170057-EI, Direct Testimony FPL witness Yupp at page 13 lines 13 – 24 and Exhibit GJY-2.
[17] See Exhibit__DJL-7
[18] See Exhibit__DJL-7

costly than simply purchasing natural gas at the market price by approximately $888 million over the ten-year measurement period.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANIES' PROPOSED OTM CALL OPTION HEDGING ALTERNATIVE?

A. While it is true that the proposed OTM call options alternative is less costly than either the current financial hedging approach or Mr. Gettings' risk responsive financial hedging model, the OTM call option hedging approach is not without substantial customer costs. As I demonstrated above, the OTM call option costs relative to market costs were $888 million over the period 2007 through 2016. Moreover, given that the natural gas market is stable with no expectations of market disruptions, the benefits of OTM call options are suspect – especially if OTM call options premium costs are substantial or increase because of the volume of OTM call options Florida utilities would start executing if the Commission authorizes this approach.

Risk-Responsive Financial Hedging

Q. PLEASE ADDRESS THE RISK RESPONSIVE FINANCIAL HEDGING ALTERNATIVE?

A. In the 2016 fuel adjustment clause docket, Docket No. 20160001-EI, Mr. Gettings filed testimony proposing what is referred to as a risk-responsive financial hedging model or program as an alternative to the current hedging programs. Under Mr. Gettings' suggested approach, the following hedging strategies are employed: (1) programmatic (fixed-percentage hedging); (2) defensive hedging; (3) contingent hedging, and (4) in rare cases, discretionary hedging. Risk-responsive financial hedging employs about a

25 percent fixed or targeted-volume hedge along with primary reliance on defensive hedges. Thus, rather than have total reliance on fixed-hedges as has been employed in Florida since 2008, Mr. Gettings proposes a smaller percentage of targeted-volume hedges (approximately half of the amount permitted under the current targeted-volume hedging programs) plus the use of defensive hedges and, in intermittent occasions, contingent hedges. In Mr. Gettings' financial hedging approach, risk of loss tolerance levels are estimated so that benefits associated with declining gas costs can be captured and locked-in for the benefit of consumers. According to Mr. Gettings, the opportunity cost experienced by Florida consumers is the failure to take advantage of declining or lower market gas prices after being locked in at high levels through the fixed-percentage hedges. Mr. Gettings asserts that his recommended lower level of fixed-hedges combined with defensive hedging strategies will mitigate these lost opportunity costs.

Contingent hedging strategies would be employed in response to hedge-loss risk by constraining hedge-loss potential. Mr. Gettings claims that a "robust" hedging program engages in hedging plans that would mainly employ these three hedging responses (fixed, defensive, and contingent) "which together constitute a comprehensive hedge strategy."[19]

Q. DOES MR. GETTINGS' PROPOSED HEDGING MODELS PROVIDE A BETTER WAY FORWARD?

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[19] Document No. 07781-2016, filed September 23, 2016, in Docket No. 20160001-EI, Direct Testimony Michael Gettings at 16

A. The answer depends on which alternative is being compared to Mr. Gettings' proposal. For example, if you compare his proposal to the status quo targeted-volume hedging, Mr. Gettings' recommendation is possibly an improvement. However, if you compare his proposal to the Companies' proposed OTM call options or to the option of discontinuing financial hedging, then the answer is an unequivocal no.

Clearly, the status quo targeted-volume hedging approach has demonstrated that enormous losses will result when hedging goals are merely limited to fixed targets no matter what the gas market or economic changes or conditions are. Certainly, this might explain why almost all the customer groups, the Companies, and Mr. Gettings have asserted that change is now necessary.

In terms of Mr. Gettings' proposal, there is substantial doubt as to whether his approach will change or limit the significant costs incurred by consumers for fuel. I have already discussed how FPL witness Yupp's analysis shows Mr. Gettings approach is likely more expensive than other alternative hedging options. More importantly, because of the increased complexity and added discretion of when and how to employ hedging given market circumstances, Mr. Gettings's risk-responsive hedging approach is likely to lead to more costs and more litigation in future fuel proceedings. This is not a desirable outcome. Such an unfortunate result is summarized by FPL witness Yupp when he states: "… such a plan would put the IOUs in a position of having to outguess the market, and the Commission in a position of having to decide whether in fact the IOUs did so prudently.'[20] The costs of hedging have been substantial and the risk-

[20] Document No. 05680-2017, filed July 3, 2017, in Docket No. 20170057-EI, Direct Testimony FPL witness

responsive hedging method would add uncertainty to the mix, potentially leading to continuous litigation over the prudence of annual hedging results.

Q. SHOULD THE COMMISSION ADOPT MR. GETTINGS' RISK-RESPONSIVE HEDGING APPROACH?

A. No. Mr. Gettings' proposal should be rejected for several reasons. First, the market for natural gas, oil, and other petroleum products has changed significantly as natural gas and petroleum reserves have substantially increased with the continued discovery and development of shale reserves in recent years. In this new market, natural gas prices have dropped substantially and are subject to significantly less volatility. Second, natural gas price forecasts show substantial gas reserves and supplies continuing into the future with modest real price escalation. Thus it is difficult to conclude that Mr. Gettings' risk-responsive hedging approach will provide better results.

For the above reasons, the proposed risk-responsive financial hedging proposal should be rejected.

SECTION IV: <u>FINANCIAL HEDGING CONCLUSIONS</u>

Q. IN YOUR OPINION, IS FINANCIAL HEDGING NECESSARY TO LIMIT VOLATILITY?

A. No, it is not. I addressed the issue of volatility in natural gas prices earlier in this testimony. Given the current long-term EIA projections of low and steady natural gas

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Yupp at page 9, lines 7 – 9.

market supply and demand balances and stable natural gas market prices, volatility is no longer the concern it once was when the Florida utilities started hedging natural gas. Thus, the markets (supply and demand balances) are addressing gas price volatility, making financial hedging less valuable. Moreover, as long as the volatility in the price of natural gas does not exceed the 10% threshold for triggering a mid-course correction to the fuel factor, customers will not experience any of the volatility inherent in the natural gas markets.

Q. DO UTILITY SHAREHOLDERS INDIRECTLY BENEFIT FROM FINANCIAL HEDGING PROGRAMS?

A. Yes, they do. When financial hedging is employed, regardless of the type of hedging program, shareholder liquidity risks are reduced. By locking in natural gas prices through financial hedging and using those locked-in prices in setting the fuel factor, fuel costs on the financially hedged gas purchases are included in the current year's fuel factor and are recovered in a timely manner. The non-hedged purchases may or may not be recovered on a current basis, meaning current under-recoveries will be incorporated into next year's fuel factor. For example, assume gas prices are higher than originally projected in the development of the fuel factor. This will result in a fuel cost under-recovery. While the utility will eventually recover the costs (absent a disallowance for extraordinary reasons), such cost recovery may take a year or more. Given that fuel purchases must be paid for currently, the mismatch between gas purchase and gas cost recovery on non-hedged gas purchases can cause cash recovery timing or liquidity issues. Liquidity risks are risks that impact shareholder return risks and these risks are reduced when fuel costs are hedged. That is why the Companies have an incentive to continue hedging, even when it makes no financial sense to do so from the customers' perspective.

FPL witness Morey Dewhurst in a deposition related to FPL's 2016 base rate case, Docket No. 20160021-EI, recently addressed the liquidity risk issue, in the context of hedging.[21] Dewhurst basically explained that because of the timing between recovery of prudently-incurred fuel costs and the funding of what could be pretty large swings in cash flow requires balance sheet and liquidity support. The bottom line is that shareholders benefitted from fuel hedging in terms of liquidity risk reductions, while at the same time costing customers approximately $6.7 billion since 2002.

Q. DO THE CUSTOMERS RECEIVE SOME BENEFIT FROM FUEL HEDGING?

A. The purported purpose of hedging is to benefit customers by insulating them from large (volatile) changes in fuel prices, which can change the fuel factor and impact customer bills. While fuel hedging is not designed to lower prices or beat the market, because beating the market is not possible in the long-term, hedging can stabilize prices to avoid the immediate impacts of large price spikes. Examples of large natural gas price spikes can be found between 2000 and 2008 in the U.S. gas markets.

The issue now is whether continued financial hedging is beneficial to customers in light of changed natural gas markets, stable gas price forecasts, and mounting hedging lost opportunity costs. The answer to that question is no – financial hedging is not currently

[21] See Deposition of Moray Dewhurst in Docket No. 20160021-EI (August 4, 2016) at pages 16-18 in Exhibit___DJL-8, Excerpt from Dewhur st Deposition.

beneficial to customers. For example, in Docket No. 20150001-EI, FPL attempted to show hedging benefits to customers in the rebuttal testimony of witness Yupp, by asserting fewer mid-course fuel cost corrections are required when fuel hedging is employed.[22] What his analysis actually demonstrates is that most of the mid-course corrections would have resulted in decreases to the fuel factor, or in customer refunds. Customer fuels cost refunds, even when requiring a mid-course correction, are not a volatility problem. Moreover, since 2010 when gas markets substantially changed due to increased shale development, only in 2014 would a mid-course correction have been required for a fuel price increase. Given that FPL's hedging costs since 2010 exceed $2.0 billion,[23] it is apparent that the hedging costs for FPL have greatly exceeded the hedging benefits for its customers. The same is true for the other Companies.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT AN ALTERNATIVE HEDGING MECHANISM?

A. No, I am not. I am recommending that the Commission discontinue the financial hedging of natural gas for the time being. Further, the Commission should continue the current moratorium on hedging for a defined minimum term, and, at the end of that term, the Commission should: (1) evaluate current market conditions and the Companies' projected natural gas purchases, and (2) consider whether additional fuel price volatility mitigating proposals should be instituted. During the moratorium, consumers will pay only the market price for natural gas. Thus, such a financial

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[22] See Document No. 06393-2015, filed October 9. 2015, in Docket No. 20150001-EI, Rebuttal testimony of FPL witness Yupp at Exhibit GJY-7, FPL's response to OPC Interrogatory No. 7, filed June 23, 2017, updated Yupp's analysis.
[23] See Table 2

hedging moratorium will result in reducing consumer costs while the Commission continues to evaluate market factors impacting natural gas price volatility. If at the end of the hedging moratorium the Commission determines market changes and volatile gas prices are causing harm to consumers, then some form of volatility mitigation mechanism or financial hedging could be implemented at that time.

Q. IN YOUR OPINION, HAS THE NATURAL GAS MARKET'S CONTINUED STEADY AND STABLE PERFORMANCE AND THE EIA'S FORECASTS FOR CONTINUED LOW AND STABLE NATURAL GAS PRICES CREATED A REASONABLE BASIS TO RECONSIDER FINANCIAL HEDGING?

A. Yes, they have. As discussed above, the natural gas markets have changed substantially over the past few years. The recent and current EIA forecasts show that natural gas production has substantially increased, forward estimates of natural gas prices have become more stable, and price volatility has declined. As discussed in my testimony in Docket No. 20150001-EI,[24] based on these factors, some regulatory authorities and utilities have concluded financial hedging is no longer necessary and, moreover, is no longer worth the risks or costs associated with financial hedging. For all of the above reasons, I recommend the Companies' and Mr. Gettings' financial hedging proposals not be approved on a going-forward basis. If circumstances change substantially, then volatility mitigation mechanism(s), like hedging, can be visited again in the future.

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[24] Document No. 06001-2015, filed September 23, 2015, Direct Testimony of Daniel J. Lawton and Exhs DJL-1 through DJL-9.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony and Exhibits of Daniel J. Lawton has been furnished by electronic mail on this 10th day of August, 2017, to the following:

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Prior to beginning his own consulting practice Diversified Utility Consultants, Inc., in 1986 where he practiced as a firm principal through December 31, 2005, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service in Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous revenue requirements, fuel reconciliation reviews, financial, and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, forecasting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses, prudence analyses, fuel cost reviews and regulatory policy issues for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and management systems for cost of service analyses.

Mr. Lawton has developed and numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility related matters. Such negotiations ranges from the settlement of electric rate cases to the negotiation of provisions in purchase power contracts.

In addition to rate consulting work Mr. Lawton through the Lawton Law Firm represents numerous municipalities in Texas before regulatory authorities in electric and gas proceedings. Mr. Lawton also represents municipalities in various contract and franchise matters involving gas and electric utility matters.

A list of cases in which Mr. Lawton has provided testimony is attached.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company	P-04-81	Cost of Capital
Municipal Light & Power	U-13-184	Cost of Capital
Enstar Natural Gas Co.	U-14-111	Cost of Capital
Enstar Natural Gas Co.	U-16-066	Cost of Capital
Municipal Light & Power	U-17-008	Cost of Capital

JURISDICTION/COMPANY	DOCKET NO.	TESTIMONY TOPIC

PUBLIC UTILITIES COMMISSION OF CALIFORNIA		
Southern California Edison	12-0415	Cost of Capital
San Diego Gas and Electric	12-0416	Cost of Capital
Southern California Gas	12-0417	Cost of Capital
Pacific Gas and Electric	12-0418	Cost of Capital

GEORGIA PUBLIC SERVICE COMMISSION		
Georgia Power Co.	25060-U	Cost of Capital

FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service

Southern California Edison	ER82-427-000	Forecasting

LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation
Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service

MARYLAND PUBLIC SERVICE COMMISSION		
Baltimore Gas and Electric Company	9173	Financial
Baltimore Gas and Electric Company	9326	Financial

MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

MISSOURI PUBLIC SERVICE COMMISSION		
Missouri Gas Energy	GR-2009-0355	Financial
Ameren UE	ER-2010-0036	Financial

FLORIDA PUBLIC SERVICE COMMISSION		
Progress Energy	070052-EI	Cost Recovery
Florida Power and Light	080677-EI	Financial
Florida Power and Light	090130-EI	Depreciation
Progress Energy	090079-EI	Depreciation
Florida Power and Light	120015-EI	Financial Metrics
Florida Power and Light	140001-EI	Economic and Regulatory Policy Issues
Florida Power and Light	150001-EI	Economic and Regulatory Policy Issues Financial Gas Hedging
Florida Power and Light	160001-EI	Economic and Regulatory Policy Issues Financial Gas Hedging
Florida Power and Light	160021-EI	Equity Bonus Rewards & Financial Metrics

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service

OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital

Public Service Company of Oklahoma	200800144	Cost of Capital
Public Service Company of Oklahoma	201200054	Financial and Earnings Related
Oklahoma Natural Gas	201500213	Return on Equity, Financial, capital Structure

PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital

PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
Nevada Power Company	08-12002	Cost of Capital
Southwest Gas Corporation	09-04003	Cost of Capital
Sierra Pacific Power Company	10-06001 & 10-06002	Cost of Capital & Financial
Nevada Power Co. and Sierra Pacific Power Co.	11-06006 11-06007 11-06008	Cost of Capital

Southwest Gas Corp.	12-04005	Cost of Capital
Sierra Power Company	13-06002 13-06003 13-06003	Cost of Capital
NV Energy & MidAmerican Energy Holdings Co.	13-07021	Merger and Public Interest Financial

PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
Rocky Mountain Power	08-035-38	Cost of Capital
Rocky Mountain Power	09-035-23	Cost of Capital
Rocky Mountain Power	10-035-124	Cost of Capital
Rocky Mountain Power	11-035-200	Cost of Capital
Questar Gas Company Rocky Mountain Power	13-057-05 13-035-184	Cost of Capital Cost of Capital

SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting

PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting

Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses
El Paso Electric Company	46831	Cost of Capital, Decommissioning Funding, Allocation
Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling
Entergy Gulf States Incorporated	22344	Capital Structure
Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction

Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
Lower Colorado River Authority	8400	Debt Service Coverage, Rate Design
Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
Southwestern Bell Telephone Company	8585	Yellow Pages
Southwestern Bell Telephone Company	18509	Rate Group Re-Classification
Southwestern Public Service Company	13456	Interruptible Rates
Southwestern Public Service Company	11520	Cost of Capital
Southwestern Public Service Company	14174	Fuel Reconciliation
Southwestern Public Service Company	14499	TUCO Acquisition
Southwestern Public Service Company	19512	Fuel Reconciliation
Texas-New Mexico Power Company	9491	Cost of Capital, Revenue Requirements, Prudence
Texas-New Mexico Power Company	10200	Prudence

Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	21112	Acquisition risks/merger benefits
Texas Utilities Electric Company	9300	Cost of Service, Cost of Capital
Texas Utilities Electric Company	11735	Revenue Requirements
TXU Electric Company	21527	Securitization of Regulatory Assets
West Texas Utilities Company	7510	Cost of Capital, Cost of Service
West Texas Utilities Company	13369	Rate Design

RAILROAD COMMISSION OF TEXAS		
Energas Company	5793	Cost of Capital
Energas Company	8205	Cost of Capital
Energas Company	9002-9135	Cost of Capital, Revenues, Allocation
Lone Star Gas Company	8664	Rate Design, Cost of Capital, Accumulated Depr. & DFIT, Rate Case Exp.
Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
Southern Union Gas Company	6968	Rate Relief
Southern Union Gas Company	8878	Test Year Revenues, Joint and Common Costs
Texas Gas Service Company	9465	Cost of Capital, Cost of Service, Allocation
TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design
Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement

Atmos	10000	Cost of Capital
ATMOS	10580	Cost of Capital

TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service

SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital

HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting

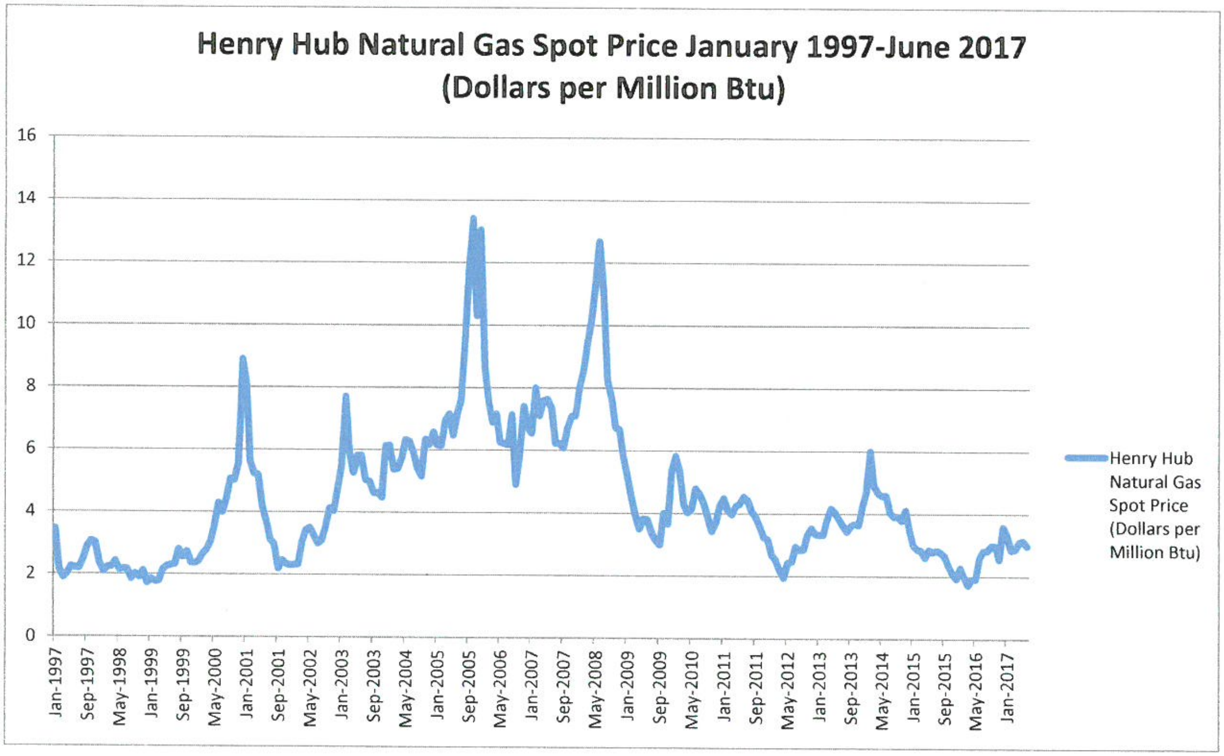
PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital

DISTRICT COURT CAMERON COUNTY, TEXAS		
City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing

DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees

DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

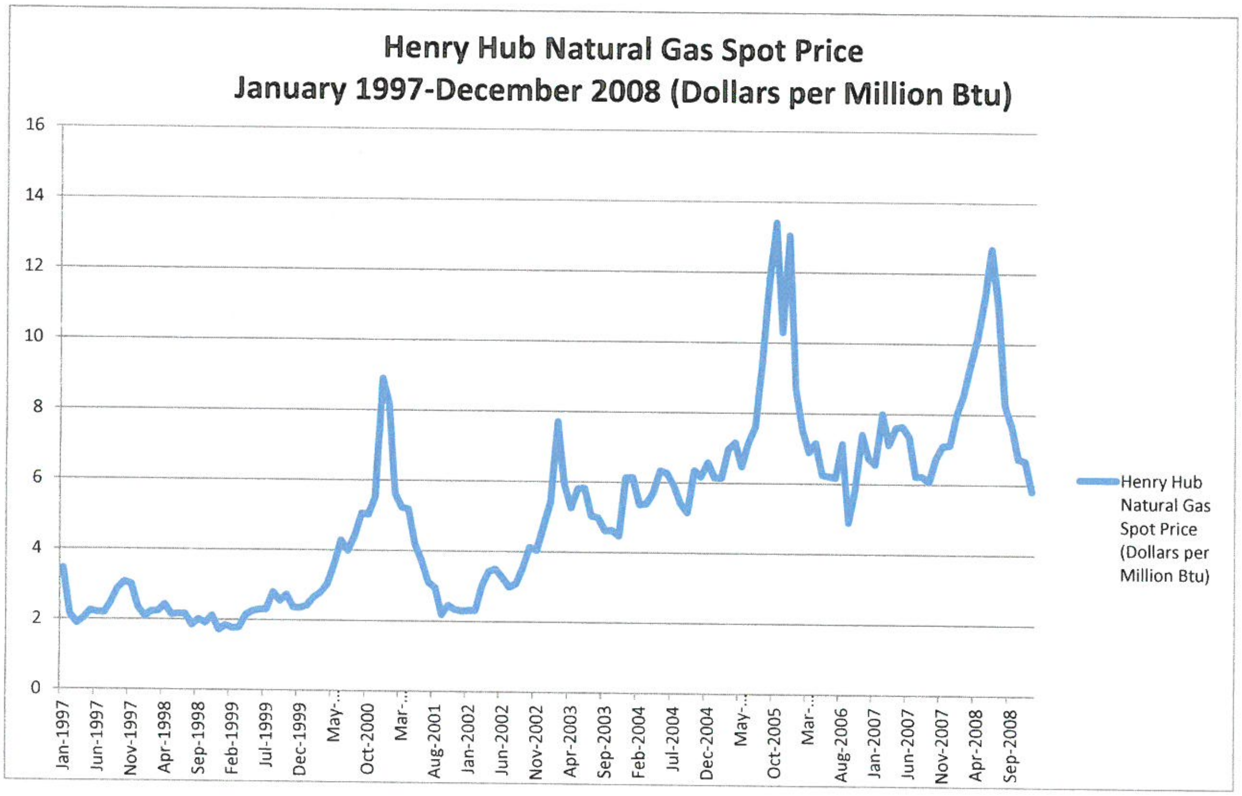
SOUTH DAYTONA, FLORIDA		
City of South Daytona v. Florida Power and Light	2008-30441-CICI	Stranded Costs



Average	$4.45
StanDev	$2.24
Min	$1.72
Max	$13.42

Data source

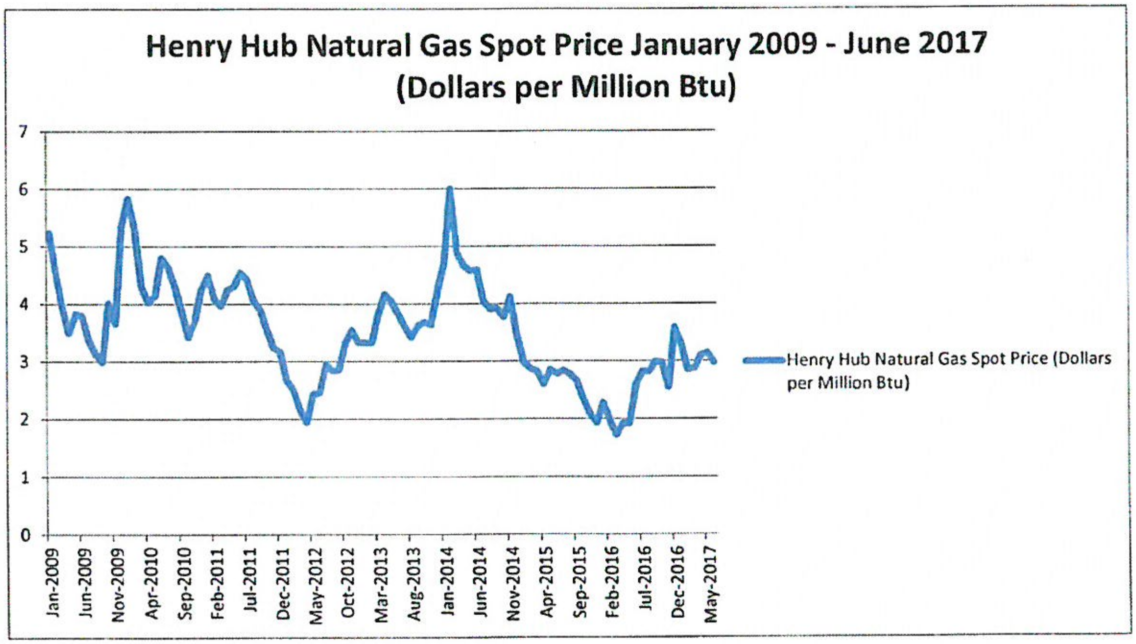
http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm



Average	$5.11
StanDev	$2.64
Min	$1.72
Max	$13.42

Data source

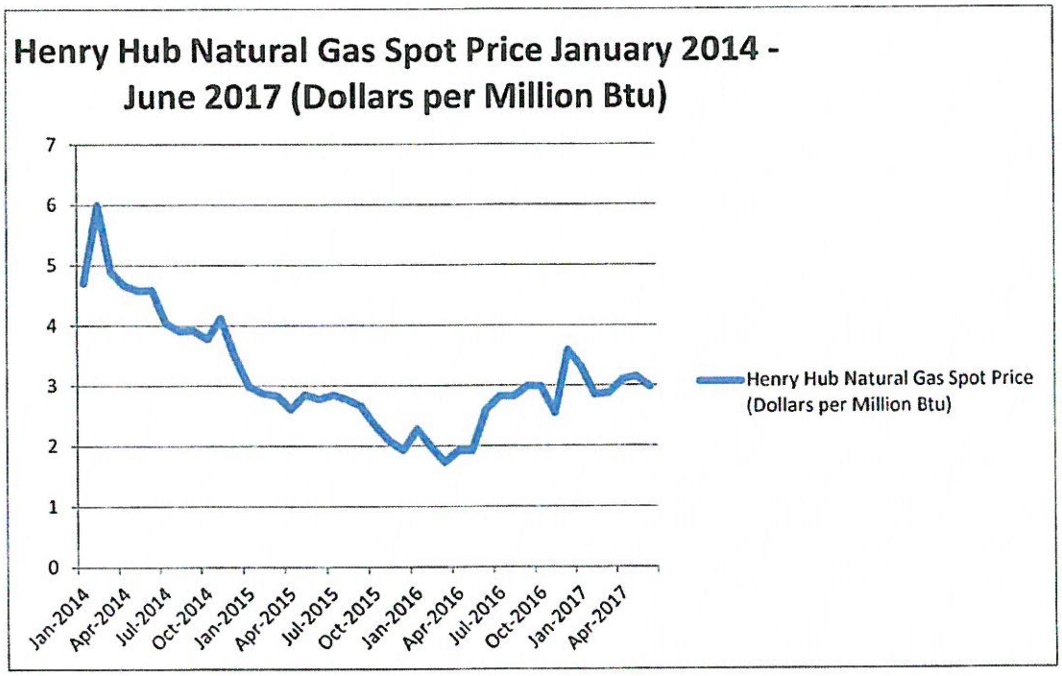
http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm



Average	$3.51
StanDev	$0.89
Min	$1.73
Max	$6.00

Data source

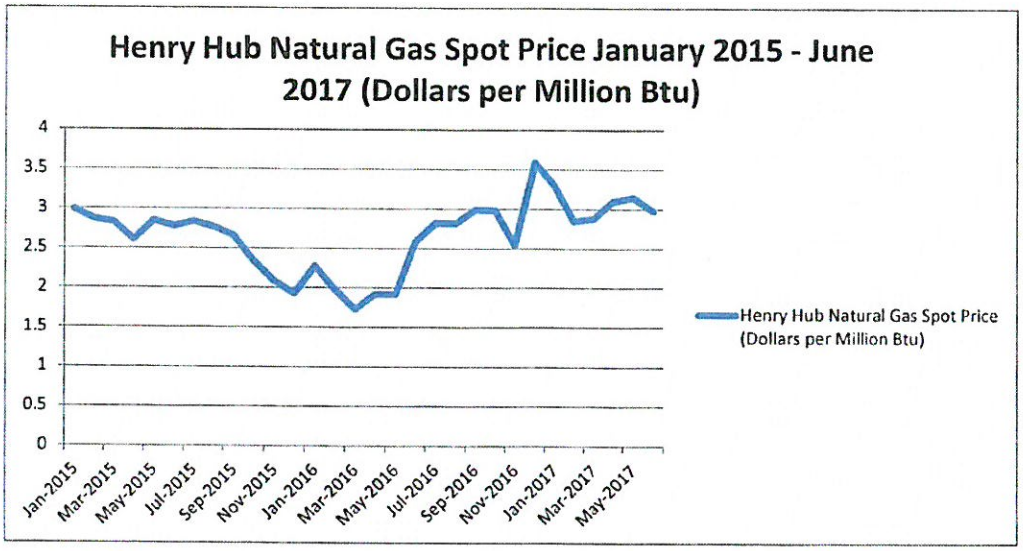
http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm



Average	$3.16
StanDev	$0.93
Min	$1.73
Max	$6.00

Data source

http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm



Average	$2.67
StanDev	$0.45
Min	$1.73
Max	$3.59

Data source

http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm

COMPARISON OF HEDGING ALTERNATIVES
FOR THE PERIOD 2007 - 2016

	A	B	C	D	E	F	G	H
	Market Settlement Prices	Hypothetical Risk-Responsive Approach Results	Hypothetical OTM Call Options Approach	Difference in Average Annual Cost Between Hypothetical Risk-Responsive Approach and OTM Call Options Approach	Hedged Gas	Market Price (No Hedging) V. Risk-Responsive Hedging Losses	Market Price (No Hedging) V. OTM Call Option Losses	Risk-Responsive V. OTM Call Option Losses
Year	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	MMBtu	$	$	$
2007	$6.86	$7.70	$7.48	($0.22)	360,000,000	($302,400,000)	($223,200,000)	($79,200,000)
2008	$9.03	$9.07	$9.24	$0.17	360,000,000	($12,960,000)	($74,880,000)	$61,920,000
2009	$3.99	$5.56	$4.42	($1.14)	360,000,000	($565,200,000)	($154,800,000)	($410,400,000)
2010	$4.39	$5.17	$4.76	($0.41)	360,000,000	($280,080,000)	($133,200,000)	($146,880,000)
2011	$4.04	$4.47	$4.33	($0.14)	360,000,000	($155,488,171)	($104,400,000)	($51,088,171)
2012	$2.79	$3.52	$2.91	($0.61)	360,000,000	($262,619,271)	($43,200,000)	($219,419,271)
2013	$3.65	$3.92	$3.81	($0.11)	360,000,000	($95,974,112)	($57,600,000)	($38,374,112)
2014	$4.42	$4.28	$4.45	$0.17	360,000,000	$49,465,964	($12,600,000)	$62,065,964
2015	$2.66	$3.27	$2.78	($0.49)	360,000,000	($218,291,637)	($42,319,416)	($175,972,221)
2016	$2.46	$2.57	$2.58	$0.01	360,000,000	($38,524,430)	($42,208,980)	$3,684,550
2007-2016 Average	$4.43	$4.95	$4.68	($0.28)	360,000,000	($1,882,071,657)	($888,408,397)	($993,663,261)

SOURCES
COLUMNS A - D: PER G. YUPP DIRECT TESTIMONY EXHIBIT GJY-2.
COLUMN E: HEDGING ASSUMPTION 60% OF 600 BCF. (600 Bcf *1000000)*60% = 360,000,000 Mcf
COLUMN F: (COLUMN A - COLUMN B) * COLUMN E
COLUMN G: (COLUMN A - COLUMN C) * COLUMN E
COLUMN H: (COLUMN C - COLUMN B) * COLUMN E

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY.
_______________________________/

DOCKET NO. 160061-EI

PETITION FOR APPROVAL OF 2016-2018 STORM HARDENING PLAN BY FLORIDA POWER & LIGHT COMPANY.
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DOCKET NO. 160062-EI

2016 DEPRECIATION AND DISMANTLEMENT STUDY BY FLORIDA POWER & LIGHT COMPANY.
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DOCKET NO. 160088-EI

PETITION FOR LIMITED PROCEEDING TO MODIFY AND CONTINUE INCENTIVE MECHANISM, BY FLORIDA POWER & LIGHT COMPANY.
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TELEPHONIC DEPOSITION OF:	MORAY DEWHURST
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 382D Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 2:00 p.m. Concluded at 6:06 p.m.
DATE:	Thursday, August 4, 2016
REPORTED BY:	ANDREA KOMARIDIS Court Reporter and Notary Public in and for the State of Florida at Large

Does FPL need a strong balance sheet to support its natural gas hedging?

A It depends. It depends, obviously, on the extent of the hedging program, but certainly that is an application of financial strength that, at various times, has benefited from the support of the balance sheet.

The balance sheet is a general resource that has, you know, multiple ways in which it can be applied. But certainly, the fuel-hedging program is one of them, but -- as is the basic fuel-purchasing program.

Q Okay. How would reducing FPL's equity ratio from 59.6 percent of investor capital to 50 percent affect FPL's ability to hedge natural gas?

A It's hard to put numbers around that. I would say it would dramatically diminish our ability to support either the hedging program or a variety of other needs.

A move from 59.6 to 50 percent would have major negative consequences in a variety of areas, but one of them would be that we would no longer have -- well, over time, we would no longer have access to the same level of liquidity and, therefore, we wouldn't be able to respond to the kinds of short-term, unexpected events that we do now.

Q And in terms of natural gas, an unexpected event might be a supply interruption and increased natural gas price in the short-term?

A Yes, those would be two major ones. To the extent that, if we are unhedged, hypothetically, and we have a significant increase in gas prices, then, obviously, we're going to have an under-recovery through the fuel clause.

We have to have the financial flexibility to be able to go out and buy the fuel, convince the suppliers that we're going to pay for it. If we don't have the balance sheet, we would not be able to do that. So, that's a fuel- -- fuel-price element. And there is certainly a fuel-supply-interruption element.

Q And I want to make sure I understand what you just told me. My understanding is that FP&L is allowed to recover its fuel costs through the fuel clause, and that those costs are trued up on an annual basis; is that right?

A That's correct; although, the true-up may be from an accrual perspective on an annual basis. The recovery of the cash may well -- and certainly in the past, has extended over more than one year.

In either case, however, we have to have the cash to be able to go and buy the fuel for the benefit of our customers. And so, the liquidity need comes in there.

So, there's a distinction between ultimate recovery of prudently-incurred costs and the need to be able to fund what can be pretty large swings in cash flow. It's swings in cash flow that require the balance sheet and liquidity support.

Q And so, basically, you're talking about being able to bridge the time in which there is a regulatory lag between having to spend the money and being able to recover it.

A Yes, but I think it's more than that because it's -- had it been able to do that and then still be in a position to continue to do all the other aspects of running the business and delivering value to customers without that changing.

So, just by way of example, in my past experience in the consulting business, I've seen plenty of examples of companies that start to get squeezed on liquidity. And one of the consequences in response to that is that they are forced to make changes on the operational side of the business which are detrimental. We want to avoid that.

Q Got it.

If the Commission were to reduce FP&L's equity