

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery
clause with generating performance incentive
factor.

DOCKET NO. 20180001-EI
ORDER NO. PSC-2018-0028-FOF-EI
ISSUED: January 8, 2018

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
ART GRAHAM
RONALD A. BRISÉ
DONALD J. POLMANN
GARY F. CLARK

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL
ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND
PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST
RECOVERY FACTOR

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Florida Public Service Commission General Counsel

BY THE COMMISSION:

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing was held on October 25-27, 2017, in this docket. White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate-White Springs (PCS Phosphate) was excused from attendance at the final hearing.

At the hearing, we voted to approve stipulated issues 1B, 2B-2I, 2Q, 2R, 3A, 6-11, 13A, 16-22, 23A, 24A-24D and 27-36 as set forth in Attachment A. We also approved Issues 1A, 2A, 4A and 5A, hedging issues contested by FRF, OPC and FIPUG, by bench decision as set forth in Attachment B. As a result of our bench decisions on these issues, we have approved all issues associated with TECO, FPUC, Gulf, and DEF. Testimony was taken on the remaining FPL issues, Issues 2J-2P, which address FPL's solar generation (SoBRA) projects. FIPUG and FPL filed briefs on the SoBRA issues on November 13, 2017. On November 16, 2017, FPL filed an Unopposed Motion for Leave to File Response to New Issue Raised in FIPUG's Post Hearing

Brief with its response attached. The new issue addressed jurisdictional recovery arguments for the SoBRA projects.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

SoBRA PROJECT RECOVERY JURISDICTION

For the first time in its post hearing brief FIPUG argued that we lack jurisdiction to allow recovery in this docket of 2017 and 2018 solar base rate adjustment charges citing the Florida Supreme Court decisions Citizens v. Graham (Woodford), 191 So. 3d 897 (Fla. 2016) and Citizens v. Graham (FPUC), 213 So. 3d 703 (Fla. 2017). FPL filed its Unopposed Motion for Leave to File Response to New Issue Raised in FIPUG's Post Hearing Brief (Motion) on November 16, 2017, with its response to the jurisdictional issue attached. FIPUG does not object to granting this Motion. The other parties to this docket, having taken no position on the SoBRA issues, Issues 2J through 2P, did not file briefs or take a position on the Motion or the underlying jurisdictional issue. Because no party has objected to FPL's request to file a written response to FIPUG's jurisdictional argument, and due process requires that FPL be given reasonable notice and a fair opportunity to be heard on this issue before a decision is made¹, we hereby grant FPL's Motion and address the jurisdictional issue below.

FIPUG characterizes the recovery of SoBRA charges as FPL's effort to again use the fuel clause to recover predictable capital costs contrary to the purpose of the fuel clause which is to address the volatility of fuel prices between base rate cases. FIPUG points out that while the Legislature has created a clause for nuclear and environmental costs, it has not provided us with express, or implied, authority for a solar energy capital cost recovery clause. FIPUG acknowledges that the process for SoBRA cost recovery being followed here is included in FPL's 2016 Stipulation and Settlement (2016 Agreement), to which it did not object. However, FIPUG counters that jurisdiction cannot be conferred by agreement of the parties or by our approval of a rate case settlement agreement.

FPL counters that FIPUG's reliance on the Woodford and FPUC decisions is misplaced for one simple reason: the capital and return on investment costs for the SoBRA projects are not being recovered through the 2017 and 2018 fuel cost recovery factors. These costs are instead being recovered through increases in FPL's base rate charge, beginning on the commercial operation date of each SoBRA project. In fact, the fuel factors to be implemented from January 1 to March 1, 2018, have been stipulated to by the parties and previously approved by us. These fuel factors cannot change no matter what our final decision on the SoBRA issues.

FPL notes that this cost recovery mechanism is similar to the generation rate base adjustment (GBRA) mechanism found in FPL's 2013 Settlement Agreement to which FIPUG was a signatory. The use of a GBRA mechanism for base rate adjustments in years beyond a test year was approved by the Florida Supreme Court in Citizens v. Public Service Commission, 146 So. 3d 1143, 1157 n.7 (Fla. 2014). Further, between 2013 and 2016, three separate generation projects (Cape Canaveral, Riviera Beach and Port Everglades) utilized the GBRA process in the fuel clause without objection by FIPUG.

¹ Citizens v. Florida Public Service Commission, 146 So. 3d 1143, 1154 (Fla. 2014).

Finally, FPL argues that filing for SoBRA recovery in the fuel docket is simply an administratively efficient process utilizing an existing docket with a known filing schedule to adjust its base rates for previously approved capital projects. This eliminates finding and scheduling separate hearing dates each year as SoBRA projects come on line and synchronizes each SoBRA rate base increase with the associated reduction in fuel costs resulting from the projects' commercial operation. Based on these facts, FPL concludes that no jurisdictional issue actually exists and that we have the authority to approve SoBRA charges in this docket.

Analysis

There is one point on which we and all parties agree: that we derive our authority to act solely from the Legislature. United Telephone Company of Florida v. Public Service Commission, 496 So. 2d 116, 118 (Fla. 1986). In Woodford, FPL sought to recover through the fuel factor the capital, operation and maintenance, and return on investment costs for wells drilled in the Woodford Shale Gas Region in Oklahoma. The Court identified our authority as the ability to "regulate and supervise each public utility with respect to its rates and service and to prescribe a rate structure for all electric utilities." Woodford, 191 So. 3d at 900. An "electric utility" is defined as a municipal or investor-owned utility or a rural electric cooperative that "owns, maintains, or operates an electric generation, transmission, or distribution system within the state." Section 366.02(2), F.S.

Based on this definition, the Court found that the exploration, drilling and production of natural gas did "not constitute generating, transmitting, or distributing electricity in Florida as the meaning of those terms are plainly understood" and "falls outside the purview of an electric utility as defined by the Legislature." Woodford, 191 So. 3d at 901. Further, the Court found that the Woodford project was not a physical hedge of fuel costs which had previously been determined by the Court to be within our regulatory authority. Id. Having determined that the Woodford project was neither an electric utility activity contemplated by the Legislature nor a physical hedge, the Court found that we had exceeded our authority in approving the project costs through the fuel clause. Woodford, 191 So. 3d at 902.

In FPUC, the Court found that we exceeded our authority by allowing the recovery through the fuel factor of capital and return on capital investment costs associated with the construction of a transmission line connecting FPUC's electric system on Amelia Island with that of FPL. The Court focused on the historical purpose of the fuel clause as a means of "adjusting for volatile costs associated with fuel" finding that a transmission line failed to meet this test. FPUC, 213 So. 3d at 718. The Court also relied heavily upon the terms of FPUC's rate case stipulation and settlement agreement, which specifically stated that FPUC could not seek recovery through the fuel clause of costs that had "traditionally and historically" been recovered through base rates and used "investment in and maintenance of transmission assets" as an example of such an expense. FPUC, 213 So. 3d at 708-10. Since no discussion of these settlement agreement terms was included in our final order, the Court found that we had "failed to perform its duty to explain its reasoning" and reversed our decision. FPUC, 213 So. 3d at 710-11.

Both the Woodford and FPUC decisions discuss what types of costs are appropriately recovered through the fuel clause factor: fuel, purchased power and volatile fuel-related costs. The FPUC decision does not address our inherent authority to allow the recovery of the FPL

transmission line. Further, if the reasoning in Woodford is applied to the FPUC facts, the Court would find the recovery of transmission lines through base rates appropriate since transmission is specifically listed as an activity engaged in by electric utilities. Section 366.02(2), F.S.

Likewise, applying the reasoning of Woodford to the facts here, there is no question that we have the authority to allow recovery of the costs associated with solar generation projects. As with transmission, generation is listed specifically as an activity engaged in by electric utilities in Section 366.02(2), F.S. It is important to note that FIPUG is not arguing that FPL does not have the right to recover the solar project costs; it is arguing that solar project costs can't be recovered through fuel clause factors. Presumably, FIPUG would not object to FPL filing a separate docket seeking cost recovery for the 2017 and 2018 solar projects using an increase in base rates to do so. Indeed, FIPUG has agreed to such a mechanism to recover solar project capital costs as a signatory to Tampa Electric Company's 2017 Amended and Restated Stipulation and Settlement Agreement.²

Since FPL is not requesting recovery through the fuel adjustment clause factor, but is requesting recovery of costs for its solar projects through increases in base rates, FIPUG's complaint does not raise a jurisdictional question at all. Recovery of these costs through base rates is clearly appropriate under both the Woodford and FPUC decisions. We agree with FPL that placement of this issue in the fuel clause docket was purely administrative. We also agree with FPL that to the extent possible, an increase in base rates associated with the solar projects coming on line should be timed to coincide with any fuel savings which result from that solar generation. Litigating the cost effectiveness issues associated with the solar projects, Issues 2J-2P, in this docket cost-effectively accomplishes this goal.

When dissected and examined closely, FIPUG's issue boils down to insisting that rate base cost recovery for the solar projects be filed in a separate docket. FIPUG has not alleged that it did not have adequate notice of the solar project issues, or that it has been harmed in any way by the inclusion of those issues in this docket. Nor could it. FPL filed direct testimony of four witnesses on this point,³ Commission staff conducted extensive discovery on this issue,⁴ FIPUG cross examined FPL witnesses Enjamio and Brannen on this topic at hearing, and FIPUG filed a post hearing brief. Conducting these activities under a separate docket number does not change their nature or provide FIPUG any additional due process rights.

Based on the above, we find that we have the authority to approve the recovery of FPL's 2017 and 2018 solar projects through base rates in this fuel clause docket.

SoBRA PROJECT RECOVERY

Overview

FPL proposes to construct and operate 596 MW of solar generation by 2018 pursuant to its 2016 Stipulation and Settlement Agreement (2016 Agreement). FPL contends that the costs for the 2017 and 2018 projects are reasonable and fall below the \$1,750 per kW_{ac} cost cap as required by the 2016 Agreement. To ensure reasonable capital costs, FPL completed a

² Document No. 07947-2017 at ¶ 6(f).

³Tiffany Cohen, Liz Fuentes, Juan Enjamio and William Brannen.

⁴EXH 84, 86, 87 and 89.

competitive bidding process for the equipment to be installed and the work to be performed. Further, FPL argues that updated efficient designs and reduced interconnection costs lowered the anticipated costs for the 2017 and 2018 projects.

FPL employed two resource plans for the proposed solar generation: a No Solar Plan and 2017-2018 Solar Plan. Based on the assumptions made in each plan, FPL calculates that there is an estimated cumulative present value revenue requirement (CPVRR) savings of \$38.6 million. FPL asserts that updates to tax law in August 2017 provided a reduction in costs, in the form of reduced property taxes, for three of the four 2018 solar project sites. FPL calculates that the efficient designs, reduced interconnection costs, and reduced property taxes raise the estimated CPVRR savings under the 2017-2018 Solar Plan to \$106 million. It is FPL's position that the 2017 and 2018 projects are cost effective under the 2016 Agreement if the system CPVRR is lower with the solar projects than without them as is the case.

FIPUG argues that the solar projects are not needed to meet the Commission's 15 percent reserve margin or FPL's 20 percent reserve margin. FIPUG contends that FPL's efforts to prove that the SoBRA projects are cost effective are only supported by hearsay evidence. FIPUG adds that FPL customers will lose \$127.3 million if fuel prices remain low and no carbon tax is imposed in the future. FIPUG further asserts that the future cost of natural gas and the future cost of carbon resulting from a carbon tax used by FPL in its cost effectiveness analysis is uncorroborated.

Analysis

A. 2017 Project Description

FPL is proposing to construct and operate four PV centers with a total nameplate capacity of 298 MW_{ac} (74.5 MW_{ac} each) with an in-service date of December 31, 2017. Construction of the 2017 solar generation projects began on October 21, 2016. The proposed solar generation projects are Fixed-Tilt Systems with an average projected first year net capacity factor of 26.6 percent. There are no upgrades to existing transmission infrastructure required as part of the construction of the 2017 solar generation projects.

The four proposed sites for the 2017 solar project construction are Coral Farms, Horizon, Wildflower, and Indian River. The Wildflower site is already included in FPL's rate base; therefore, Wildflower land costs are not included in the analysis. All other parcels are new purchases. Not all of the land in the seven newly purchased sites is being used for the 2017 and 2018 solar projects although FPL states that some of this land will be used for future projects. To develop a better understanding of the ratio of land that could be used for future development, a more detailed breakdown of each site was requested from FPL. This breakdown included four categories: total acreage, acreage used by the projects (Site Acreage), non-usable land, and residual land. Residual land consists of property that could possibly be used in future solar developments on the site, and for sites with adequate amounts of residual land, FPL will consider leasing land to parties for farming or cattle grazing activities. The range of acreages of each site is illustrated in Table 1 below:

Table 1
Land Usage

Site Name	Total Acreage (acres)	Site Acreage (acres)	Non-Usable Land (acres)	Residual Land (acres)
Coral Farms	587	541	0	46
Horizon	1316	552	178	587
Wildflower	721	466	12	244
Indian River	697	389	56	252

Source: EXH 87-88

B. 2018 Project Description

FPL is proposing to construct and operate four PV centers with a total nameplate capacity of 298 MW_{ac} (74.5 MW_{ac} each) for an in-service date of March 1, 2018. Construction of the 2018 solar generation projects began on October 21, 2016. The proposed solar generation projects are Fixed-Tilt Systems with an average projected first year net capacity factor of 26.6 percent. There are no upgrades to existing transmission infrastructure required as part of the construction of the 2018 solar generation projects.

The four proposed sites for the 2018 solar project construction are Loggerhead, Barefoot Bay, Hammock, and Blue Cypress. All parcels are new purchases. Not all of the land purchased is being used for construction of the solar projects at the four sites. To develop a better understanding of the ratio of land that could be used for future development, a more detailed breakdown of each site was requested from FPL. This breakdown included four categories: total acreage, acreage used by the projects (Site Acreage), non-usable land, and residual land. Residual land consists of property that could possibly be used in future solar developments on the site, and for sites with adequate amounts of residual land, FPL will consider leasing land to parties for farming or cattle grazing activities. The range of acreages of each site is illustrated in Table 2 below:

Table 2
Land Usage

Site Name	Total Acreage (acres)	Site Acreage (acres)	Non-Usable Land (acres)	Usable Land (acres)
Loggerhead	564	425	27	112
Barefoot Bay	462	384	52	25
Hammock	957	407	375	176
Blue Cypress	424	418	0	6

Source: EXH 87-88

C. Standard for Approval

The SoBRA projects for 2017 and 2018 for which FPL is seeking approval and cost recovery are part of its 2016 Agreement approved by Order No. PSC-16-0560-AS-EI.⁵ The 2016 Agreement allows FPL to construct up to 300 MW per calendar year of solar capacity

⁵Order No. PSC-16-0560-AS-EI, issued on December 15, 2016, in Docket No. 20160021-EI, In re: Petition for rate increase by Florida Power & Light Company.

during the period 2017-2021 and to recover through base rates the incremental annualized base revenue requirement for those facilities for the first 12 months of operation commencing when the facilities are placed into service.⁶ There are several conditions that must be met for recovery in this case. First, FPL must request recovery for these projects during the term of the 2016 Agreement, or prior to December 31, 2020. Second, the cost of the components, engineering, and construction for any solar project is capped at \$1,750 per kilowatt alternating current (kW_{ac}). Third, for projects less than 75 MW (as are all of the projects proposed in this case): 1) the request for base rate recovery must be filed in the Fuel Clause docket as part of its final true-up filing; and 2) the issues are “limited to the cost effectiveness of each such project (i.e., will the project lower the projected system CPVRR as compared to each CPVRR without the solar project) and the amount of revenue requirements and appropriate percentage in base rates needed to collect the estimated revenue requirements.”⁷ If the project meets these requirements, the terms of the 2016 Agreement have been met. Therefore, we find that FIPUG’s argument based on reliability criteria is irrelevant.

D. 2017 and 2018 Solar Project Cost Effectiveness Analysis

The in-service date for the 2017 projects is December 31, 2017. The in-service date for the 2018 projects is March 1, 2018. Because of the minor timing difference between the in-service dates, we find that it is appropriate to evaluate both 2017 and 2018 projects together for cost effectiveness. In addition, both the 2017 and 2018 solar generation projects were cumulatively evaluated in the initial filing of the docket.

FPL developed two resource plans to form the basis of the cost effectiveness analysis that it performed. These two resource plans are called the No Solar Plan and 2017-2018 Solar Plan. The No Solar Plan assumes that resource needs will be met by combined cycle units and short term purchase power agreements (PPAs) through the year 2030. The 2017-2018 Solar Plan takes into account the eight solar projects, which initially defers the 2025 combined cycle (cc) unit. The Okeechobee CC Unit is currently under construction. The resource plan filed in regards to FPL’s initial filing is shown in Table 3 below:

Table 3
Initial Resource Plan

Year	No Solar Resource Plan	2017-2018 Solar Resource Plan
2017		298 MW Solar
2018		298 MW Solar
2019	Okeechobee 3x1 CC Unit	Okeechobee 3x1 CC Unit
2020		
2021		
2022		
2023		
2024	1-Year 33 MW PPA	
2025	1 Greenfield 3x1 CC Unit	1-Year 119 MW PPA
2026		1 Greenfield 3x1 CC Unit

⁶2016 Agreement at ¶ 10(a).

⁷2016 Agreement at ¶ 10(c).

2027		
2028	1-Year 20 MW PPA	
2029	1 Greenfield 3x1 CC Unit	1-Year 287 MW PPA
2030		1 Greenfield 3x1 CC Unit
2031	Turkey Point 6	Turkey Point 6
2032	Turkey Point 7	Turkey Point 7
2033	Equalizing 599 MW CC	Equalizing 291 MW CC

Source: EXH 84

FPL filed its 2017 Ten Year Site Plan in April 2017, which included for the first time the Dania Beach Clean Energy Center. In August 2017, FPL filed revised testimony that updated its evaluation of the 2017 and 2018 solar projects. Table 4 below is based on a new resource plan incorporating both the FPL's revised filing and the addition of the Dania Beach Clean Energy Center.

Table 4
Revised Resource Plan

Year	No Solar Resource Plan	2017-2018 Solar Resource Plan
2017		298 MW Solar
2018	1-Year 958 MW PPA	298 MW Solar; 1-Year 636 MW PPA
2019	Okeechobee 3x1 CC Unit; 1-Year 155 MW PPA	Okeechobee 3x1 CC Unit
2020	1-Year 182 MW PPA	
2021	1-Year 263 MW PPA	
2022	Dania Beach CC	Dania Beach CC
2023		
2024	1-Year 44 MW PPA	
2025	1 Greenfield 3x1 CC Unit	1-Year 149 MW PPA
2026		1 Greenfield 3x1 CC Unit
2027		
2028	1-Year 93 MW PPA	
2029	1 Greenfield 3x1 CC Unit	1-Year 363 MW PPA
2030		1 Greenfield 3x1 CC Unit
2031	Turkey Point 6	Turkey Point 6
2032	Turkey Point 7	Turkey Point 7
2033	Equalizing 574 MW CC	Equalizing 266 MW CC

Source: EXH 87

The revised resource plan shows that the addition of the 2017 and 2018 solar projects should reduce FPL's need for purchased power agreements.

In completing the analysis, FPL considered multiple components to determine cost effectiveness: solar revenue requirements, avoided generation costs, and avoided system costs. For the proposed solar facilities, the revenue requirements included fixed operation and maintenance (O&M), equipment, installation, land cost, and transmission interconnection cost.

The avoided generation cost component considered avoided generation capital, avoided fixed O&M, avoided transmission interconnection, avoided capital replacement, incremental gas transport, and short-term purchases. The avoided system cost component considers the factors of fuel savings, avoided variable O&M, and emission cost savings. FPL’s CPVRR analysis assumed that each project had an actual life of 33 years, with the analysis ending in 2050.

The emission cost savings consideration did not incorporate CO₂ pricing until 2028. FPL witness Enjamio identified ICF’s CO₂ emission’s cost forecast as a major assumption in FPL’s economic analysis of its proposed solar PV generation projects. The CO₂ cost projections used in FPL’s cost-effectiveness analyses are based on ICF’s CO₂ emission cost forecast dated December 2016. ICF is a consulting firm with extensive experience in forecasting the cost of air emissions and is recognized as one of the industry leaders in this field. FPL has used ICF’s CO₂ emission cost forecasts in many of its filings, including the recently approved 2017 Ten Year Site Plan. No intervenor offered testimony rebutting FPL’s CO₂ emission cost forecast or provided any alternative emission cost forecast. For these reasons, we find that the CO₂ cost projections FPL used in this docket are reasonable and appropriate.

1. CPVRR Analysis - Initial Filing

We reviewed FPL’s original CPVRR for the 2017 and 2018 solar generation projects that produced a savings of \$38.6 million for the base fuel and environmental forecasts. This calculation included the previously mentioned CO₂ pricing in 2028. FPL’s CPVRR analysis in support of its 2017-2018 Solar Plan included assumptions related to future fuel prices. The Company employed its standard fuel forecasting methodology to produce its long-term fuel price forecast. No alternative base fuel forecast was provided to us for the purposes of evaluating the Company’s 2017-2018 Solar Plan. We find that the forecasted fuel prices used in the Company’s CPVRR analysis associated with its current proposal are reasonable. FPL provided a CPVRR analysis with both fuel and environmental compliance sensitivities. In FPL’s analysis, a Low, Medium, and High Fuel Forecast and ENV I, ENV II, and ENV III compliance costs were considered. ENV I assumes an annual \$0/ton cost for CO₂ pricing and low environmental compliance costs, ENV II assumes a most likely cost, and ENV III assumes high environmental compliance costs. The range of savings is illustrated in Table 5 below:

Table 5
Initial CPVRR Filing

	Environmental Compliance Cost Forecast			
		ENV I	ENV II	ENV III
Fuel Cost Forecast	High	(\$63.5)	(\$136.4)	(\$291)
	Medium	\$35	(\$38.6)	(\$195.8)
	Low	\$127.3	\$53.6	(\$103.1)

Source: EXH 84

2. CPVRR Analysis - Revised Filing

FPL witness Enjamio filed revised testimony August 2, 2017, providing an updated economic analysis to reflect a change in cost effectiveness and cost assumptions for the 2017-

2018 solar projects. Specifically, FPL cited changes in tax law effective as of July 1, 2017, that allowed an exemption from property taxes for qualifying solar installations which applied to three of the planned 2018 solar generation project sites, and resulted in a \$34 million CPVRR reduction. This testimony resulted in a revised \$106 million CPVRR base case scenario.

The terms of the 2016 agreement also require FPL to adhere to a \$1,750 per kW_{ac} cost cap for any solar project. This cost cap includes the cost of the components, engineering, and construction for each site. In the initial filing, the 2017 and 2018 solar generation projects had a total anticipated capital cost of \$435 million and \$457 million, respectively. The 2017 projects were projected to fall under the cost cap with an average cost of \$1,461 per kW_{ac} and a \$1,534 per kW_{ac} average cost for the 2018 projects. In witness Brannen's revised testimony of August 2, 2017, the completion of design competitive solicitations for the construction of the interconnection facilities for the 2017 solar construction projects reduced the projected construction cost by \$16 Million. Witness Brannen stated that these same factors also reduced the projected construction cost by \$14 million for the 2018 solar construction projects. For the 2017 projects, the new construction cost was a \$419 million total with a revised average \$1,405 per kW_{ac} cost. The new cost per kW_{ac} is \$56 per kW_{ac} less than the initially filed cost and \$345 per kW_{ac} less than the \$1,750 per kW_{ac} cost cap. For the 2018 projects, the new construction cost was a \$443 million total with a revised average \$1,485 per kW_{ac} cost. The new cost per kW_{ac} is \$49 per kW_{ac} less than the initially filed cost and \$265 per kW_{ac} less than the \$1,750 per kW_{ac} cost cap. Having reviewed the cost cap assumptions discussed above we find them to be reasonable.

FPL's revised testimony from August 2017 did not include the planned Dania Beach Clean Energy Center. As such, an updated CPVRR evaluation was requested that included the planned Dania Beach Clean Energy Center and updated fuel and environmental compliance sensitivities evaluations. The result of this updated sensitivity analysis is illustrated in Table 6 below:

Table 6
Revised CPVRR Analysis

		Environmental Compliance Cost Forecast		
		ENV I	ENV II	ENV III
Fuel Cost Forecast	High	(\$119)	(\$195)	(\$348)
	Medium	(\$24)	(\$96)	(\$249)
	Low	\$76	\$6	(\$147)

Source: EXH 87

Table 6 above shows that in seven of the nine scenarios, the 2017 and 2018 solar projects are cost effective. Notably the base fuel case (medium), ENV I scenario contains no cost for CO₂, but is also cost effective. When comparing the change in savings on a CPVRR basis between the initial filing and the revised analysis, there is a substantial increase in savings for all forecasted scenarios. In all forecasted scenarios, avoided fuel costs was the major driving force in producing overall savings for the projects. This fact manifested in even the "worst" case scenario of Low Fuel Cost, ENV I, where there are projected fuel savings in every forecasted year. The first cumulative benefit occurs in 2025. This benefit seems to be driven by the

avoided capital that would be required for the Greenfield 3x1 Combined Cycle Unit. For the reasons discussed above, we find that FPL's CPVRR assumptions are reasonable.

FIPUG questions the validity of CO₂ emission cost forecasts. However, FPL performed CO₂ emission and natural gas price sensitivities analyses, including zero carbon tax scenarios, to support its petition. Results of such sensitivity analyses show that the 2017 and 2018 solar projects are cost-effective in seven out of nine fuel and CO₂ sensitivity scenarios, including scenarios that assume zero CO₂ cost. The CPVRR and construction cost analyses were performed in a consistent manner and no party presented substantial evidence disputing either the input assumptions or the analyses.

Based on the evidence contained in the record, we find that FPL's proposed 2017 and 2018 solar projects are projected to produce savings under multiple scenarios. FPL has also met the terms of 2016 Agreement in regards to keeping construction cost under the \$1,750 per kW_{ac} cost cap. Therefore, we find that the terms and conditions of the 2016 Agreement have been met and that the 2017 and 2018 solar projects are cost effective.

E. 2017 SoBRA Revenue Requirement

Witness Fuentes testified that the annualized jurisdictional revenue requirement for the first 12 months of operations related to the 2017 SoBRA projects is \$60,523,000. Witness Fuentes further stated that the \$60,523,000 revenue requirement was calculated by following the methodologies approved by the Commission for FPL's generation base rate adjustments (GBRA) for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-05-0902-S-EI,⁸ West County Energy Center Unit 3 in Order No. PSC-11-0089-S-EI,⁹ and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-13-0023-S-EI.¹⁰ Witness Fuentes also testified that the same methodology was used with the recently approved 2019 Okeechobee Limited Scope Adjustment (Okeechobee LSA). The jurisdictional annualized revenue requirement calculation for the 2017 SoBRA projects used several inputs, including the most current estimated capital expenditures presented by FPL witness Brannen.

FIPUG did not sponsor a witness to address this issue, and waived cross-examination of FPL witness Fuentes. In its brief, FIPUG only presented arguments about FPL's reserve margin, the overall cost effectiveness of the 2017 SoBRA projects, and the appropriate cost recovery mechanism for these projects, but did not specifically address this issue.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Fuentes for determining the amount of revenue requirement associated with the 2017 SoBRA projects, we find them to be reasonable and set the jurisdictional annualized revenue requirements associated with the 2017 SoBRA projects at \$60,523,000.

⁸Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 20050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and in Docket No. 20050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company.

⁹Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket No. 20080677-EI, In re: Petition for increase in rates by Florida Power & Light Company, and in Docket No. 20090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.

¹⁰Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

F. 2017 Base Rate Percentage Increase

The SoBRA factors are incremental cost recovery factors that will be applied to base rate charges in order for the Company to collect the revenue necessary to recover the costs associated with building and operating the 2017 SoBRA projects. Witness Cohen testified that the SoBRA factors are based on the ratio of the Company’s jurisdictional revenue requirements for each Project (by year) and the forecasted retail base revenue from electricity sales for the first twelve months of each rate year, beginning January 1, 2018 for the 2017 Project and March 1, 2018 for the 2018 Project. Witness Cohen also presented an exhibit to demonstrate the inputs and calculations performed to determine the resulting incremental cost recovery factor of 0.937 percent for the 2017 SoBRA projects.

FPL asserted in its brief that even when all of the SoBRA projects are reflected in customer bills, FPL’s typical residential bills will remain below national and statewide averages. Table 7 below reflects the base rate changes and fuel cost recovery changes that will occur for typical monthly residential bills for customers using 1,000 kWh of electricity. Column 3 in Table 7 reflects a typical bill before the application of incremental cost recovery factors for any SoBRA projects. Column 4 in Table 6 reflects a typical bill for a residential customer using 1,000 kWh of electricity when the incremental cost recovery factor of 0.937 percent for the 2017 SoBRA projects is applied, and Column 5 reflects a typical bill for a residential customer using 1,000 kWh of electricity when all of the projects are implemented.¹¹

Table 7
FPL Typical 1,000-kWh Residential Customer Bill Comparison For 2018

(1)	(2)	(3)	(4)	(5)
Bill Components	Present (2017)	Approved in the 2016 Settlement Agreement (Jan, 2018)	Proposed for the 2017 SoBRA Projects (Jan & Feb, 2018)	Proposed for the 2017 & 2018 SoBRA Projects (March, 2018)
Base Rate Charges	\$63.49	\$65.88	\$66.49	\$67.10
Fuel Cost Recovery	\$24.91	\$23.35	\$23.17	\$22.97
Other Charges	<u>\$14.15</u>	<u>\$13.11</u>	<u>\$13.12</u>	<u>\$9.68</u>
TOTAL	<u>\$102.55</u>	<u>\$102.34</u>	<u>\$102.78</u>	<u>\$99.75</u>

Source: (EXH 51, Exhibit TCC-5, Page 1 of 5)

¹¹The estimates shown in Column 4 reflect the application of the incremental cost recovery factor of 0.937 percent for the Horizon, Wildflower, Indian River, and Coral Farms solar generation facilities (2017 SoBRA projects). The estimates shown in Column 5 reflect the data in Column 4 plus the application of the incremental cost recovery factor presented in Issue 20 for the Loggerhead, Barefoot Bay, Hammock, and Blue Cypress solar generation facilities (2018 SoBRA projects). The data presented in Table 7 was prepared based on an exhibit FPL witness Cohen filed on March 1, 2017. That exhibit and this data do not reflect any storm-related charges attributable to named storms that impacted FPL’s service territory in the 2017 hurricane season.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen, and did not specifically address this issue in its brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Cohen for determining the appropriate incremental cost recovery factor associated with the 2017 SoBRA projects we find that the appropriate base rate percentage increase (SoBRA Factor) for the 2017 SoBRA projects is 0.937 percent.

G. 2018 SoBRA Revenue Requirement

Witness Fuentes testified that the annualized jurisdictional revenue requirement for the first 12 months of operations related to the 2018 SoBRA projects is \$59,890,000. Witness Fuentes further stated that the revenue requirement was calculated by following the methodologies approved by this Commission for FPL's generation base rate adjustments (GBRA) for Turkey Point Unit 5 and West County Energy Center Units 1 and 2 in Order No. PSC-05-0902-S-EI,¹² West County Energy Center Unit 3 in Order No. PSC-11-0089-S-EI,¹³ and the modernization projects at Canaveral, Riviera Beach, and Port Everglades in Order No. PSC-13-0023-S-EI.¹⁴ Witness Fuentes also testified that the same methodology was used with the recently approved 2019 Okeechobee Limited Scope Adjustment (Okeechobee LSA). The jurisdictional annualized revenue requirement calculation for the 2018 SoBRA projects used several inputs, including the most current estimated capital expenditures presented by FPL witness Brannen.

FIPUG did not sponsor a witness to address this issue, and waived cross-examination of FPL witness Fuentes. In its brief, FIPUG only presented arguments about FPL's reserve margin, the overall cost effectiveness of the 2018 SoBRA projects, and the appropriate cost recovery mechanism for these projects, but did not specifically address this issue.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Fuentes for determining the amount of revenue requirement associated with the 2018 SoBRA projects we find them to be reasonable and set the jurisdictional annualized revenue requirement associated with the 2018 SoBRA projects at \$59,890,000.

H. 2018 Base Rate Percentage Increase

Similar to the 2017 recovery factors, the 2018 SoBRA factors are incremental cost recovery factors that will be applied to base rate charges in order for the Company to collect the revenue necessary to recover the costs associated with building and operating the 2018 SoBRA projects. The SoBRA recovery factors are based on the ratio of the Company's jurisdictional revenue requirements for each Project (by year) and the forecasted retail base revenue from electricity sales for the first twelve months of each rate year, beginning January 1, 2018 for the

¹²Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 20050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and in Docket No. 20050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company.

¹³Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket No. 20080677-EI, In re: Petition for increase in rates by Florida Power & Light Company, and in Docket No. 20090130-EI, In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.

¹⁴Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

2017 Project and March 1, 2018 for the 2018 Project. Exhibit 7 demonstrates the inputs and calculations performed by witness Cohen to determine the resulting incremental cost recovery factor of 0.919 percent for the 2018 SoBRA projects.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen, and did not specifically address this issue in its brief.

Having reviewed the testimony, exhibits, and calculations used by FPL witness Cohen for determining the appropriate incremental cost recovery factor associated with the 2018 SoBRA projects, we find that the appropriate base rate percentage increase (SoBRA Factor) for the 2018 SoBRA projects is 0.919 percent.

I. SoBRA tariffs for 2017 and 2018 projects

FPL witness Cohen sponsored exhibits that summarize the tariff changes for all SoBRA projects. The 2017 SoBRA projects are scheduled to enter commercial service by December 31, 2017, and the 2018 SoBRA projects by March 1, 2018. It is FPL's intention to submit revised tariff sheets reflecting the Commission-approved charges if the SoBRA and the associated charges are approved for both the 2017 and 2018 solar projects. FPL further requests that the 2017 and 2018 project tariff sheets become effective on or after the date that each set of projects is placed into service upon written notice to the Commission.

FIPUG did not sponsor a witness to address this issue, waived cross-examination of FPL witness Cohen. In its brief, FIPUG argued that the SoBRA projects were not needed and, therefore, the tariffs should not be approved.

Based on our approval of the 2017 and 2018 SoBRA projects, we hereby approve tariffs sheets which reflect our decisions with an effective date on or after the date that the 2017 and 2018 SoBRA projects are placed into service upon written notice being filed with the Clerk. Further, we direct our staff to verify that the tariffs are consistent with our decision.

OTHER MATTERS

Per stipulation of the parties, the new fuel adjustment and capacity factors shall become effective beginning with the first billing cycle for January 2018 through the last billing cycle for December 2018. The first billing cycle may start before January 1, 2018, and the last cycle may be read after December 31, 2018, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by us.

We hereby approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. We direct staff to verify that the revised tariffs are consistent with our decision.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of, and Attachments A and B to, this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby

authorized to apply the fuel cost recovery factors set forth herein during the period January 2018 through December 2018. It is further

ORDERED that the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further


ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Duke Energy Florida, LLC, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors set forth herein during the period January 2018 through December 2018. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding are hereby approved and we direct Commission staff to verify that the revised tariffs are consistent with our decision. It is further

ORDERED that while the Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor docket is assigned a separate docket number each year for administrative convenience, it is a continuing docket and shall remain open.

By ORDER of the Florida Public Service Commission this 8th day of January, 2018.



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

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

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

Any party adversely affected by the Commission's final action in this matter may request:

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

APPROVED TYPE 2 STIPULATIONS¹⁵

ISSUE 1B: What adjustments, if any are needed to account for replacement power costs associated with the February 2017 outage at the Bartow generating plant?

STIPULATION:

Duke Energy Florida and the parties stipulate that Duke has not included the approximately \$10,973,639 in retail replacement power associated with the unplanned Bartow outage in developing rates for 2018. These costs will remain in the over/under account to be considered in Docket 20180001-EI for recovery in 2019 rates subject to normal intervenor challenge and Commission reasonableness and prudence review and approval.

ISSUE 2B: What is the total gain in 2016 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, and how is that gain to be shared between FPL and customers?

STIPULATION:

The total gain in 2016 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, was \$62,835,808. This amount exceeded the sharing threshold of \$46 million, and therefore the incremental gain above that amount shall be shared between FPL and customers (60% and 40%, respectively), with FPL retaining \$10,101,485.

ISSUE 2C: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016?

STIPULATION:

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL shall be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016 is \$484,305.

ISSUE 2D: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of \$514,000 megawatt-hours for the period January 2016 through December 2016?

¹⁵ A Type 2 Stipulation is one in which all parties either agree with, do not object to, or take no position on, the stipulation presented.

STIPULATION:

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL shall be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016 is \$2,671,992.

ISSUE 2E: What is the appropriate amount of actual/estimated Incremental Optimization Costs under the Incentive Mechanism approved by Order No. PSC-16-0560-AS-EI that FPL may recover through the fuel clause for the period January 2017 through December 2017?

STIPULATION:

For the period January 2017 through December 2017, FPL reported Incremental Personnel, Software, and Hardware Costs of \$701,442.

ISSUE 2F: What is the appropriate amount of actual/estimated variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2017 through December 2017?

STIPULATION:

For the period January 2017 through December 2017, FPL reported Variable power plant O&M Attributable to Off-System Sales of \$1,250,109, and also Variable power plant O&M Avoided due to Economy Purchases of \$(817,813). The sum of these amounts is \$432,296.

The appropriate amount of actual/estimated variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2017 through December 2017 is \$432,296.

ISSUE 2G: What is the appropriate amount of projected Incremental Optimization Costs under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018?

STIPULATION:

The appropriate amount of projected Incremental Optimization Costs under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018 is \$484,870.

ISSUE 2H: What is the appropriate amount of projected variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018?

STIPULATION:

The appropriate amount of projected variable power plant O&M expenses under the revised Incentive Mechanism that FPL may recover through the fuel clause for the period January 2018 through December 2018 is \$496,340.

ISSUE 2I: Have all Woodford-related costs been removed from FPL's requested true-up and projected fuel costs?

STIPULATION:

Yes. FPL's final true-up calculations for 2016 reflect that \$126,520 of Woodford-related costs have been removed from FPL's requested true-up and projected fuel costs for the period of January-December, 2016. There are no actual/estimated Woodford-related costs for the period of January-December, 2017, and no estimated Woodford-related costs for the period of January-December, 2018.

ISSUE 2Q: Has FPL properly reflected in the fuel and purchased power cost recovery clause the effects of the Indiantown Cogeneration L.P. (Indiantown) facility transaction approved by the Commission in Docket No 160154-EI?

STIPULATION:

Yes. In Schedule E1-B (Line 4, Column 15), FPL reflected \$3,164,987 in Rail Car Lease amounts for the Actual/Estimated period of January-December, 2017 (of this amount \$1,288,762 is related to Indiantown). In Schedule E2 (Line 3, Column 15), FPL reflected \$2,195,706 in Rail Car Lease amounts for the Estimated period of January-December, 2018 (of this amount \$1,123,366 is related to Indiantown).

ISSUE 2R: How should the effects on the 2018 Fuel and Capacity Clause factors of the St. Johns River Power Park Transaction (SJRPP Transaction), approved by the Commission on September 25, 2017, be addressed?

STIPULATION:

At the time that FPL made its 2018 Fuel and Capacity Clause projection filing, this Commission was not expected to make a decision on the SJRPP Transaction until after the hearing in this docket, so FPL did not reflect the impacts of that transaction in the calculation of its 2018 Fuel or Capacity Clause factors. However, on September 25, 2017 this Commission approved FPL's and

OPC's stipulation and settlement resolving all issues concerning the SJRPP Transaction. The net impact of the SJRPP Transaction will be a reduction in customer bills for 2018. At this point, FPL cannot prepare and file an updated filing reflecting the SJRPP Transaction in time for parties to have a reasonable opportunity to review it before the hearing scheduled in this docket on October 25-27, 2017. Therefore, FPL proposes to file a mid-course correction for the impacts of the SJRPP Transaction by no later than November 17, 2017, to allow ample time for Commission staff and parties to review and conduct discovery, if any, before the mid-course correction is brought to this Commission for decision at the February 6, 2018 Agenda Conference, with the intent that the revised Fuel and Capacity factors go into effect on March 1, 2018.

ISSUE 3A: What amount should be refunded through the Fuel Clause to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project?

STIPULATION:

\$221,415 shall be refunded through the Fuel Clause to customers as a result of the Florida Supreme Court's March 16, 2017 decision on the FPL Interconnection Line project. This amount includes all actual/estimated costs associated with the FPL Interconnection Line project. Schedule E1-b (Page 2 of 3 of Exhibit MC-1) properly reflects the credit of \$221,415 in purchased power costs for the FPL Interconnection Line project for the period of January-December, 2017.

ISSUE 6: What are the appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

STIPULATION:

The appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: \$3,019,369.

FPL: Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2016-0560-AS-EI, FPL revised its Incentive Mechanism program, which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its revised Incentive Mechanism.

GULF: \$872,163.

TECO: \$1,493,095.

ISSUE 7: What are the appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

STIPULATION:

The appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: \$1,771,110.

FPL: Pursuant to the Stipulation and Settlement that was approved in Order No. PSC-2016-0560-AS-EI, FPL revised its Incentive Mechanism program, which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its revised Incentive Mechanism.

GULF: \$1,009,272

TECO: The appropriate estimated benchmark levels for calendar year 2018 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is \$881,855. However, on September 27, 2017, Docket Number 20170210-EI was opened to address the Tampa Electric Company Petition for Limited Proceeding to Approve 2017 Amended and Restated Stipulation and Settlement Agreement (2017 ARSSA Petition).

If the 2017 ARSSA Petition is approved, an optimization mechanism will replace incentive program for non-separated wholesale energy sales.

ISSUE 8: What are the appropriate final fuel adjustment true-up amounts for the period January 2016 through December 2016?

STIPULATION:

The appropriate final fuel adjustment true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: The final adjustment true-up amount for the period January 2016 through December 2016 is \$58,893,512, under-recovery. The final true-up amount for the period January 2016 through December 2016 is \$85,111,174, under-recovery.

FPL: The final adjustment true-up amount for the period January 2016 through December 2016 is of \$28,780,519, under-recovery. The final true-up amount for the period January 2016 through December 2016 is \$55,264,203, under-recovery.

FPUC: The final adjustment true-up amount for the period January 2016 through December 2016 is of \$2,415,898, under-recovery. The final true up amount for the period January 2016 through December 2016 is \$3,705,790, under-recovery.

GULF: The final adjustment true-up amount for the period January 2016 through December 2016 is of \$10,797,411, under-recovery. The final true up amount for the period January 2016 through December 2016 is \$16,586,321, over-recovery.

TECO: The final adjustment true-up amount for the period January 2016 through December 2016 is of \$21,571,557, under-recovery. The final true up amount for the period January 2016 through December 2016 is \$101,068,239, over-recovery.

ISSUE 9: What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2017 through December 2017?

STIPULATION:

The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2017 through December 2017 are as follows:

DEF: \$136,610,259, under-recovery.

FPL: \$45,572,897, over-recovery.

FPUC: \$975,518, under-recovery.

GULF: \$21,853,354, under-recovery.

TECO: \$38,652,694, over-recovery.

ISSUE 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2018 through December 2018?

STIPULATION:

The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate total fuel adjustment true-up amount to be collected from January 2018 through December 2018 is \$97,751,887.

If the 2017 RRSSA Petition is not approved, the appropriate total fuel adjustment true-up amount to be collected from January 2018 through December 2018 is \$195,503,774.

FPL: \$16,792,378, to be refunded (over-recovery).

FPUC: \$3,391,416, to be collected (under-recovery).

Gulf: \$32,650,765, to be collected (under-recovery).

TECO: \$17,081,137, to be refunded (over-recovery).

ISSUE 11: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018?

STIPULATION:

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: \$1,496,427,570.

FPL: \$2,870,532,871, which excludes prior period true up amounts, revenue taxes, the GPIF reward, and FPL's portion of gains from its Incentive Mechanism. The replacement power costs and other related costs associated with the August 2016 and January 2017 unplanned outages at St. Lucie Unit I, lasting 27 and 7 days, respectively, and the March 2017 unplanned outage at Turkey Point Unit 3 lasting 9 days are included in this amount. Parties reserve the right to challenge the prudence of FPL's actions or inactions related to the cause of these outages and to seek refunds of the corresponding replacement power costs and other related costs in a subsequent Fuel and Purchased Power Cost Recovery Clause docket.

FPUC: \$58,791,697.

GULF: \$415,320,095, including prior period true up amounts and revenue taxes.

TECO: \$610,721,792, which is adjusted by the jurisdictional separation factor, excluding the GPIF reward and the revenue tax factor, but including the prior period true up amounts.

ISSUE 13A: What are the appropriate adjustments to FPL’s 2017 GPIF targets/ranges to reflect the effects of the Indiantown transaction approved by the Commission in Docket No. 160154-EI?

STIPULATION:

At the time that FPL set its GPIF targets and ranges for the January 2017 through December 2017 period, this Commission had not yet approved the Indiantown transaction identified in Docket No. 20160154-EI. By Order No. PSC-2016-0506-FOF-EI,¹⁶ this Commission approved the Indiantown transaction. Thereafter, FPL recalculated the 2017 GPIF targets and ranges to reflect the effects of the Indiantown transaction approved by this Commission.

The appropriate adjustment to FPL’s GPIF targets/ranges for the period January through December 2017, is that the weighted system ANOHR target should be 7,263 Btu/kWh, slightly lower than the prior weighted system ANOHR target of 7,275. The weighted system EAF target of 86.2% remains unchanged.

FPL’s revised GPIF targets/ranges that reflect the effects of the Indiantown transaction approved by the Commission are shown in Table 13A-1 below:

**Table 13A-1
 FPL’s Revised GPIF Targets/Ranges for the period January-December, 2017**

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
FPL	Canaveral 3	79.4	82.4	1,132	6,661	6,742	2,566
	Manatee 3	70.9	72.9	480	6,962	7,142	4,011
	Ft. Myers 2	92.4	94.9	921	7,301	7,512	8,452
	Martin 8	72.9	75.4	537	6,977	7,090	2,529
	St. Lucie 1	93.6	96.6	5,184	10,401	10,509	576
	St. Lucie 2	83.7	86.7	3,765	10,278	10,372	427
	Turkey Point 3	85.1	88.1	3,830	11,106	11,286	730

¹⁶ Order No. PSC-16-0506-FOF, issued November 2, 2016, in Docket No. 160154-EI, In re: Petition for approval of a purchase and sale agreement between Florida Power & Light Company and Calypso Energy Holdings, LLC, for the ownership of the Indiantown Cogeneration LP and related power purchase agreement.

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
	Turkey Point 4	85.4	88.4	4,062	11,019	11,168	590
	Turkey Point 5	78.3	80.3	560	7,136	7,218	1,632
	West County 1	89.5	92	791	6,951	7,137	6,225
	West County 2	93	95.5	862	6,911	7,049	4,874
	West County 3	76.1	78.6	830	6,980	7,121	3,975
	Total			22,954			36,587

Source: GPIF Target and Range Summary, Pages 6-7 of 34 (Exhibit CRR-3)

ISSUE 16: What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF?

STIPULATION:

The appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2016 through December 2016 for each investor-owned electric utility subject to the GPIF is as follows:

- DEF \$2,793,216 reward.
- FPL \$9,656,036 reward.
- GULF \$2,043,225 penalty.
- TECO \$47,392 reward.

ISSUE 17: What should the GPIF targets/ranges be for the period January 2018 through December 2018 for each investor-owned electric utility subject to the GPIF?

STIPULATION:

The appropriate GPIF targets/ranges be for the period January 2018 through December 2018 for each investor-owned electric utility subject to the GPIF are shown in Tables 17-1 through 17-4 below:

DEF: See Table 17-1 below:

FPL: See Table 17-2 below:

Gulf: See Table 17-3 below:

TECO: See Table 17-4 below:

**Table 17-1
 DEF GPIF Targets/Ranges for the period January-December, 2018**

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
DEF	Bartow 4	90.20	93.82	2,025	7,916	8,600	12,851
	Crystal River 4	87.06	89.54	1,497	10,112	10,537	5,439
	Crystal River 5	92.30	94.76	1,524	9,905	10,383	6,665
	Hines 1	92.36	93.25	252	7,314	7,797	4,759
	Hines 2	68.97	80.88	5,452	7,357	7,706	1,948
	Hines 3	87.04	88.43	515	7,285	7,708	4,074
	Hines 4	83.25	87.98	2,711	7,066	7,346	2,679
	Total			13,976			38,415

Source: GPIF Target and Range Summary, Page 4 of 76 (Exhibit MJJ-1P)

Table 17-2
FPL GPIF Targets/Ranges for the period January-December, 2018

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
FPL	Canaveral 3	86.4	89.4	1,373	6,637	6,744	2,708
	Manatee 3	92.9	94.9	517	6,939	7,118	2,967
	Ft. Myers 2	85.9	88.4	578	7,240	7,356	2,583
	Martin 8	80.5	83.0	657	7,006	7,163	2,743
	Riveria 5	85.4	87.9	1,351	6,601	6,679	2,074
	St. Lucie 1	85.0	88.0	3,916	10,441	10,545	481
	St. Lucie 2	85.1	88.1	3,241	10,303	10,385	357
	Turkey Point 3	82.1	85.1	3,119	11,044	11,235	718
	Turkey Point 4	93.6	96.6	3,597	10,970	11,177	863
	West County 1	79.1	82.1	1,297	6,974	7,104	3,038
	West County 2	89.3	91.8	1,252	6,885	6,992	2,745
	West County 3	80.4	82.9	1,075	6,974	7,078	2,397
	Total			21,973			23,674

Source: GPIF Target and Range Summary, Pages 6-7 of 34 (Exhibit CRR-2)

Table 17-3
GULF 2018 GPIF Targets/Ranges for the period January-December, 2018

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
GULF	Scherer 3	97.2	98.1	12	10,495	10,810	2,089
	Crist 7	82.1	83.4	3	10,503	10,818	500
	Daniel 1	82.2	84.5	0	12,205	12,571	65
	Daniel 2	90.7	92.9	1	12,429	12,802	147
	Smith 3	93.2	93.7	83	6,932	7,140	3,095
	Total			99			5,896

Source: GPIF Unit Performance Summary, Page 41 of 64 (Exhibit CLN-2, Schedule 3)

**Table 17-4
 TECO 2018 GPIF Targets/Ranges for the period January-December, 2018**

GPIF Targets / Ranges for the period January 2018 through December 2018							
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
TECO	Big Bend 2	61.5	68.2	615.6	11,320	11,798	778.3
	Big Bend 3	66.7	72.4	1,079.4	10,619	10,987	1,448.4
	Big Bend 4	78.7	82.0	1,473.1	10,448	10,830	2,146.5
	Polk 1	74.4	77.0	211.9	9,978	10,312	1,028.0
	Polk 2	83.2	85.7	1,408.9	7,382	7,936	13,242.8
	Bayside 1	82.5	83.8	770.2	7,489	7,619	1,359.6
	Bayside 2	77.3	79.1	1,505.7	7,676	7,905	2,106.5
	Total				7,064.8		

Source: GPIF Target and Range Summary, Page 4 of 40 (Exhibit BSB-2, Document 1)

ISSUE 18: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018?

STIPULATION:

The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018 is \$1,598,120,482.

If the 2017 RRSSA Petition is not approved, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2018 through December 2018 is \$1,695,942,751.

FPL: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is \$2,874,984,279, including

prior period true-ups, revenue taxes, FPL's portion of Incentive Mechanism gains, and the GPIF reward.

FPUC: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is \$62,183,113, which includes prior period true up amounts.

GULF: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is \$413,276,870, including prior period true up amounts and revenue taxes.

TECO: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2018 through December 2018 is \$627,802,929, which is adjusted by the jurisdictional separation factor. The amount is \$611,208,904 when the GPIF reward or penalty, the revenue tax factor, and the prior period true up amounts are applied.

ISSUE 19: What is the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2018 through December 2018?

STIPULATION:

The appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2018 through December 2018 is 1.00072.

ISSUE 20: What are the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018?

STIPULATION:

The appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 are as follows:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 is 4.127 cents per kWh (adjusted for jurisdictional losses).

If the 2017 RRSSA Petition is not approved, the appropriate levelized fuel cost recovery factors for the period January 2018 through December 2018 is 4.380 cents per kWh (adjusted for jurisdictional losses).

FPL: For the period January and February, 2018 the appropriate levelized fuel cost recovery factor is 2.650 cents per kWh (adjusted for jurisdictional losses). For the period March-December, 2018 the appropriate levelized fuel cost recovery factor is 2.630 cents per kWh (adjusted for jurisdictional losses).

FPUC: The appropriate factor is 6.506¢ per kWh.

GULF: 3.789 cents/kWh.

TECO: The appropriate factor is 3.127 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage.

ISSUE 21: **What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class?**

STIPULATION:

The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown below:

DEF: See Table 21-1 below:

Table 21-1
DEF Fuel Recovery Line Loss Multipliers
for the period January-December, 2018

Group	Delivery Voltage Level	Line Loss Multiplier
A.	Transmission	0.98
B.	Distribution Primary	0.99
C.	Distribution Secondary	1.00
D.	Lighting Service	1.00

Source: Menendez Aug. 24, 2017 & Sept. 1, 2017 Testimony, Pages 2-3.

FPL: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are provided in response to Issue No. 22.

FPUC: The appropriate fuel recovery line loss multiplier to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class is 1.0000.

GULF: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are provided in response to Issue No. 22.

TECO: See Table 21-2 below:

Table 21-2
TECO Fuel Recovery Line Loss Multipliers
for the period January-December, 2018

Delivery Voltage Level	Line Loss Multiplier
Distribution Secondary	1.00
Distribution Primary	0.99
Transmission	0.98
Lighting Service	1.00

Source: Schedule E1-D, Page 5 of 30 (Exhibit PAR-3, Document 2)

ISSUE 22: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

STIPULATION:

The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-1 through 22-11 below:

DEF: On August 29, 2017, Docket Number 20170183-EI was opened to address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-1 below, and if the 2017 RRSSA Petition is not approved, the appropriate fuel cost recovery factors shown in Table 22-1A below:

Table 22-1
Fuel Cost Recovery Factors for DEF with approval of RRSSA Petition

Fuel Cost Recovery Factors For the Period January-December, 2018						
Line	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use	
		First Tier	Second Tier	Levelized	On-Peak Multiplier 1.236	Off-Peak Multiplier 0.890
1	Distribution Secondary	3.838	4.838	4.132	5.107	3.677
2	Distribution Primary	--	--	4.091	5.056	3.641
3	Transmission	--	--	4.049	5.005	3.604
4	Lighting Secondary	--	--	3.945	--	--

Source: Schedule E1-E, Page 1 of 1 (Alternative Exhibit CAM-3, Part 2)

Table 22-1A
Fuel Cost Recovery Factors for DEF without approval of RRSSA Petition

Fuel Cost Recovery Factors For the Period January-December, 2018						
Line	Delivery Voltage Level	Fuel Cost Recovery Factors (cents/kWh)			Time of Use	
		First Tier	Second Tier	Levelized	On-Peak Multiplier 1.236	Off-Peak Multiplier 0.890
1	Distribution Secondary	4.091	5.091	4.385	5.420	3.903
2	Distribution Primary	--	--	4.341	5.365	3.863
3	Transmission	--	--	4.297	5.311	3.824
4	Lighting Secondary	--	--	4.186	--	--

Source: Schedule E1-E, Page 1 of 1 (Exhibit CAM-3, Part 2)

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Tables 22-2 through 22-5 below:

Table 22-2
FPL Fuel Cost Recovery Factors for the period January:February, 2018

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
For the Period January 2018 through the day prior to the 2018 SoBRA in-service date (projected to be February 28, 2018)				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.650	1.00206	2.317
	RS-1, all addl. kWh	2.650	1.00206	3.317
	GS-1, SL-2, GSCU-1, WIES-1	2.650	1.00206	2.655
A-1	SL-1, OL-1, PL-1 ¹⁷	2.553	1.00206	2.558
B	GSD-1	2.650	1.00202	2.655
C	GSLD-1, CS-1	2.650	1.00150	2.654
D	GSLD-2, CS-2, OS-2, MET	2.650	0.99635	2.640
E	GSLD-3, CS-3	2.650	0.97646	2.588
A	GST-1 On-Peak	3.156	1.00206	3.163
	GST-1 Off Peak	2.438	1.00206	2.443
	RTR-1 On-Peak	-	-	0.508
	RTR-1 Off-Peak	-	-	(0.212)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.156	1.00202	3.162
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.438	1.00202	2.443
C	GSDLT-1, CST-1, HLFT-2 (500-1,999 kW) On Peak	3.156	1.00150	3.161
	GSDLT-1, CST-1, HLFT-2 (500-1,999 kW) Off Peak	2.438	1.00150	2.442
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.156	0.99672	3.146
	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.438	0.99672	2.430
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.156	0.97646	3.082
	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.438	0.97646	2.381
F	CILC-1(D), ISST-1(D) On Peak	3.156	0.99627	3.144
	CILC-1(D), ISST-1(D) Off Peak	2.438	0.99627	2.429

Source: Schedule E1-E, Page 1 of 2 (Appendix II of Exhibit RBD-5)

Table 22-3
FPL Fuel Cost Recovery Factors for the period January-December, 2018

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June - September, 2018				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	3.790	1.00202	3.798
	GSD(T)-1 Off-Peak	2.507	1.00202	2.512
C	GSLD(T)-1 On-Peak	3.790	1.00150	3.796
	GSLD(T)-1 Off-Peak	2.507	1.00150	2.511
D	GSLD(T)-2 On-Peak	3.790	0.99672	3.778
	GSLD(T)-2 Off-Peak	2.507	0.99672	2.499

Source: Schedule E1-E, Page 2 of 2 (Appendix II of Exhibit RBD-5)

¹⁷Weighted Average 16% On-Peak and 84% Off-Peak

Table 22-4
FPL Fuel Cost Recovery Factors for the period March-December, 2018

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
From the 2018 SoBRA in-service date (projected to be March 1, 2018) through December 2018-				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.630	1.00206	2.297
	RS-1, all addl. kWh	2.630	1.00206	3.297
	GS-1, SL-2, GSCU-1, WIES-1	2.630	1.00206	2.635
A-1	SL-1, OL-1, PL-1 ¹⁸	2.534	1.00206	2.539
B	GSD-1	2.630	1.00202	2.635
C	GSLD-1, CS-1	2.630	1.00150	2.634
D	GSLD-2, CS-2, OS-2, MET	2.630	0.99635	2.620
E	GSLD-3, CS-3	2.630	0.97646	2.568
A	GST-1 On-Peak	3.132	1.00206	3.138
	GST-1 Off Peak	2.420	1.00206	2.425
	RTR-1 On-Peak	-	-	0.503
	RTR-1 Off-Peak	-	-	(0.210)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.132	1.00202	3.138
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.420	1.00202	2.425
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	3.132	1.00150	3.137
	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.420	1.00150	2.424
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.132	0.99672	3.122
	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.420	0.99672	2.412
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.132	0.97646	3.058
	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.420	0.97646	2.363
F	CILC-1(D), ISST-1(D) On Peak	3.132	0.99627	3.120
	CILC-1(D), ISST-1(D) Off Peak	2.420	0.99627	2.411

Source: Schedule E1-E, Page 1 of 2 (Appendix III of Exhibit RBD-6)

Table 22-5
FPL Fuel Cost Recovery Factors for the period March-December, 2018

Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors				
For the Period June - September, 2018				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	3.761	1.00202	3.769
	GSD(T)-1 Off-Peak	2.488	1.00202	2.493
C	GSLD(T)-1 On-Peak	3.761	1.00150	3.767
	GSLD(T)-1 Off-Peak	2.488	1.00150	2.492
D	GSLD(T)-2 On-Peak	3.761	0.99672	3.749
	GSLD(T)-2 Off-Peak	2.488	0.99672	2.480

Source: Schedule E1-E, Page 2 of 2 (Appendix III of Exhibit RBD-6)

¹⁸Weighted Average 16% On-Peak and 84% Off-Peak

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2018 through December 2018 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Tables 22-6 through 22-8 below:

Table 22-6
FPUC Fuel Cost Recovery Factors for the period January-December, 2018

Fuel Recovery Factors – By Rate Schedule	
For the Period January through December, 2018	
Rate Schedule	Levelized Adjustment (cents/kWh)
RS	9.666
GS	9.391
GSD	9.029
GSLD	8.769
LS	7.136

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

Table 22-7
FPUC Fuel Cost Recovery Factors for the period January-December, 2018

Step Rate Allocation For Residential Customers (RS Rate Schedule)	
For the Period January through December, 2018	
Rate Schedule and Allocation	Levelized Adjustment (cents/kWh)
RS Rate Schedule – Sales Allocation	9.666
RS Rate Schedule with less than 1,000 kWh/month	9.320
RS Rate Schedule with more than 1,000 kWh/month	10.570

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

Table 22-8
FPUC Fuel Cost Recovery Factors for the period January-December, 2018

Fuel Recovery Factors for Time Of Use – By Rate Schedule		
For the Period January through December, 2018		
Rate Schedule	Levelized Adjustment On Peak (cents/kWh)	Levelized Adjustment Off Peak (cents/kWh)
RS	17.720	5.420
GS	13.391	4.391
GSD	13.029	5.779
GSLD	14.769	5.769
Interruptible	7.269	8.769

Source: Schedule E1, Page 3 of 3 (Exhibit MC-2)

GULF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Tables 22-9 and 22-10 below:

**Table 22-9
 GULF Fuel Cost Recovery Factors for the period January-December, 2018**

Group	Standard Rate Schedules	Fuel Recovery Loss Multipliers	Fuel Cost recovery Factors (cents/kWh)
A	RS,RSVP, RSTOU,GS,GSD, GSTOU,SBS,OSIII	1.00555	3.810
B	LP,SBS	0.99188	3.758
C	PX, RTP, SBS	0.97668	3.701
D	OSI/II	1.00560	3.776

Source: Schedule E1-E, Page 8 of 41 (Exhibit CSB-6)

**Table 22-10
 GULF Fuel Cost Recovery Factors for the period January-December, 2018**

Group	Time Of Use Rate Schedules*	Fuel Recovery Loss Multipliers	Fuel Cost Recovery Factors ¢/KWH	
			On-Peak	Off-Peak
A	GSDT	1.00555	4.391	3.570
B	LPT	0.99188	4.332	3.521
C	PXT	0.97668	4.265	3.467

Source: Schedule E1-E, Page 8 of 41 (Exhibit CSB-6)

TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses for the period January 2018 through December 2018, are shown in Table 22-11 below:

**Table 22-11
 TECO Fuel Cost Recovery Factors for the period January-December, 2018**

Metering Voltage Level	Fuel Cost Recovery Factors (cents per kWh)		
	Levelized Fuel Recovery Factor	First Tier (Up to 1,000 kWh)	Second Tier (Over 1,000 kWh)
STANDARD			
Distribution Secondary (RS only)	--	2.818	3.818
Distribution Secondary	3.132		
Distribution Primary	3.101		
Transmission	3.069		
Lighting Service	3.095		
TIME OF USE			
Distribution Secondary- On-Peak	3.330		
Distribution Secondary- Off-Peak	3.047		
Distribution Primary- On-Peak	3.297		
Distribution Primary- Off-Peak	3.017		
Transmission – On-Peak	3.263		
Transmission – Off-Peak	2.986		

Source: Schedule E1-E, Document Number 2, Page 6 of 30 (Exhibit PAR-3)

ISSUE 23A: Has DEF included in the capacity cost recovery clause the nuclear cost recovery amount ordered by the Commission in Docket No. 170009-EI?

STIPULATION:

On August 15, 2017, this Commission authorized DEF to include the nuclear cost recovery amount of \$49,648,457 in the calculation of its capacity cost recovery factors for the period January through December, 2018 and DEF has appropriately included this amount. If this Commission does not approve the 2017 Settlement, the Levy project will be addressed as set forth in Commission Order No. PSC-2017-0341-PCO-EI, dated August 30, 2017.

ISSUE 24A: Has FPL included in the capacity cost recovery clause the nuclear cost recovery amount ordered by the Commission in Docket No. 20170009-EI?

STIPULATION:

Yes. FPL included the nuclear cost recovery amount of \$7,305,202, over-recovery, in the calculation of its capacity cost recovery factors for the period January through December 2018. In the event that this Commission determines at the October 17, 2017 Special Agenda Conference for Docket 20170009-EI that a different amount is applicable, FPL will reflect the impact of that different amount in the mid-course correction for the SJRPP transaction as described in Issue 2R. Notwithstanding Rule 25-6.0423(6)(c)4, Florida Administrative Code,

FPL shall file that mid-course correction by no later than November 17, 2017, with the intent that the revised Fuel and Capacity factors go into effect on March 1, 2018. This stipulation is without prejudice as to the ultimate amount to be recovered or refunded by FPL.

ISSUE 24B: Has FPL properly reflected in the capacity cost recovery clause the effects of the Indiantown transaction approved by the Commission in Docket No. 160154-EI?

STIPULATION:

Yes. In its 2017 CCR Actual/Estimated True-up filing (Exhibit RBD-4, Page 9 of 15), FPL reflected \$89,421,413 in Total Recoverable Costs for the Indiantown transaction for the Actual/Estimated period of January-December, 2017. \$50,166,667 of this amount is the Regulatory Asset related to the loss of the Indiantown Purchase Power Agreement, and \$39,254,746 is the amount for the Total Return Requirements.

In its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 14 of 29), FPL reflected \$84,768,867 in Total Recoverable Expenses for the Indiantown transaction for the Estimated period of January-December, 2018. \$50,166,667 of this amount is the Regulatory Asset related to the loss of the Indiantown Purchase Power Agreement, and \$34,602,200 is the amount for the Total Return Requirements.

ISSUE 24C: What are the appropriate Indiantown non-fuel base revenue requirements to be recovered through the Capacity Clause pursuant to the Commission's approval of the Indiantown transaction in Docket No. 160154-EI for 2017 and 2018?

STIPULATION:

In its 2017 CCR Actual/Estimated True-up filing (Exhibit RBD-4, Page 11 of 15), FPL reflected \$13,626,163 in Revenue Requirement Allocation for the Indiantown transaction for the period of January-December, 2017.

In its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 18 of 29), FPL reflected \$4,022,504 in Revenue Requirement Allocation for the Indiantown transaction for the period of January-December, 2018.

ISSUE 24D: Is \$5,155,918 the appropriate refund amount associated with the Port Everglades Energy Center (PEEC) GBRA true-up?

STIPULATION:

Yes. The PEEC GBRA refund accrual is \$5,099,063, and the cumulative interest is \$56,855. As stated in its 2018 CCR Projection filing (Exhibit RBD-8, Appendix V, Page 1 of 29), the appropriate PEEC Generating Base Rate Adjustment cumulative refund amount, including interest, is \$5,155,918.

ISSUE 27: What are the appropriate final capacity cost recovery true-up amounts for the period January 2016 through December 2016?

STIPULATION:

The appropriate final capacity cost recovery true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is \$2,203,058, over-recovery. The final true-up amount for the period January 2016 through December 2016 is \$16,868,290, over-recovery.

FPL: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is \$7,586,581, over-recovery. The final true-up amount for the period January 2016 through December 2016 is \$17,227,490, over-recovery.

GULF: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is \$545,959, over-recovery. The final true-up amount for the period January 2016 through December 2016 is \$695,190, over-recovery.

TECO: The final capacity cost recovery adjustment true-up amount for the period January 2016 through December 2016 is \$4,411,715, under-recovery. The final true-up amount for the period January 2016 through December 2016 is \$7,397,775, under-recovery.

ISSUE 28: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2017 through December 2017?

STIPULATION:

The appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2017 through December 2017 are as follows:

DEF: \$7,324,397, under-recovery.

FPL: \$6,649,359, under-recovery.

GULF: \$3,698,545, under-recovery.

TECO: \$1,648,777, over-recovery.

ISSUE 29: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2018 through December 2018?

STIPULATION:

The appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2018 through December 2018 are as follows:

DEF: \$5,121,339, under-recovery.

FPL: \$937,222, over-recovery.

GULF: \$3,152,586, under-recovery.

TECO: \$2,762,938, under-recovery.

ISSUE 30: What are the appropriate projected total capacity cost recovery amounts for the period January 2018 through December 2018?

STIPULATION:

The appropriate projected total capacity cost recovery amounts for the period January 2018 through December 2018 are as follows:

DEF: Schedule E12-A (Page 1 of 2 of Exhibit CAM-3, Part 3) reflects the total projected purchased power capacity cost recovery amount for the period January 2018 through December 2018, excluding revenue taxes, is \$404,721,485.

FPL: \$289,174,210.

GULF: \$75,738,532.

TECO: \$8,131,950.

ISSUE 31: What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2018 through December 2018?

STIPULATION:

DEF: Schedule E12-A (Page 1 of 2 of Exhibit CAM-3, Part 3) reflects the total projected purchased power capacity cost recovery amount for the period January 2018 through December 2018, excluding nuclear cost recovery clause amounts and adjusted for revenue taxes, is \$410,137,911. The total projected ISIFI Costs for the period January 2018 through December 2018, adjusted for revenue taxes, is \$9,315,359. The sum of these amounts is \$419,453,270, which is the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2018 through December 2018.

FPL: \$279,996,930, which includes all prior period true-up amounts, nuclear cost recovery amounts, the Port Everglades Energy Center GBRA True-up, the Indiantown non-fuel based revenue requirement, and revenue taxes.

GULF: \$78,947,920, which includes all prior period true-up amounts and revenue taxes.

TECO: \$10,902,732, which includes all prior period true-up amounts and revenue taxes.

ISSUE 32: What are the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2018 through December 2018?

STIPULATION:

The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2018 through December 2018 are as follows:

DEF: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%.

FPL: See Table 32-1 below:

**Table 32-1
FPL Jurisdictional Separation Factors
for the period January-December, 2018**

Demand	Separation Factor
Transmission	0.887974
System Average Production Demand (Base & Solar)	0.956652
Contract Adjusted Demand – Intermediate	0.941431
Contract Adjusted Demand – Peaking	0.947386
Distribution	1.000000

Source: Exhibit RBD-8

GULF: The appropriate jurisdictional separation factors are:
FPSC 97.18277%
FERC 2.81723%

TECO: The appropriate jurisdictional separation factor is 1.00.

ISSUE 33: What are the appropriate capacity cost recovery factors for the period January 2018 through December 2018?

STIPULATION:

The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Tables 33-1 through 33-6 below.

DEF: On August 29, 2017, Docket Number 20170183-EI was opened the address the Duke Energy Florida, LLC Petition for Limited Proceeding to Approve 2017 Second Revised and Restated Stipulation and Settlement Agreement (2017 RRSSA Petition).

If the 2017 RRSSA Petition is approved, the appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-1 below.

If the 2017 RRSSA Petition is not approved, the capacity cost recovery factors beginning January 2018 will be the same as those listed in Table 33-1 pending the outcome of the deferred Levy-portion of the 2017 NCRC hearing.

**Table 33-1
DEF Capacity Cost Recovery Factors for the period January-December, 2018
(with approval of RRSSA Petition)**

Rate Class	2018 Capacity Cost Recovery Factors	
	Cents / kWh	Dollars / kW-month
Residential (RS-1, RST-1, RSL-1, RSL-2, RSS-1)	1.433	
General Service Non-Demand (GS-1, GST-1)		
	At Secondary Voltage	1.117
	At Primary Voltage	1.106
	At Transmission Voltage	1.095
General Service (GS-2)	0.782	
General Service Demand (GSD-1, GSDD-1, SS-1)		
	At Secondary Voltage	4.06
	At Primary Voltage	4.02
	At Transmission Voltage	3.98
Curtable (CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3)		
	At Secondary Voltage	2.66
	At Primary Voltage	2.63
	At Transmission Voltage	2.61
Interruptible (IS-1, IST-1, IS-2, IST-2, SS-2)		
	At Secondary Voltage	3.09
	At Primary Voltage	3.06
	At Transmission Voltage	3.03
Standby Monthly (SS-1, 2, 3)		
	At Secondary Voltage	0.393
	At Primary Voltage	0.389
	At Transmission Voltage	0.385
Standby Daily (SS-1, 2, 3)		
	At Secondary Voltage	0.187
	At Primary Voltage	0.185
	At Transmission Voltage	0.183
Lighting (LS-1)	0.227	

Source: Schedule E12-E, Pages 3-4 of 4 (Exhibit CAM-3, Part 3)

FPL: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Tables 33-2 through 33-4 below:

Table 33-2
FPL Capacity Cost Recovery Factors for the period January-December, 2018

Rate Schedule	2018 Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW ¹⁹	Sum of Daily Demand Charge (SDD) \$/kW ²⁰
RS1/RTR1	-	0.00277	-	-
GS1/GST1	-	0.00259	-	-
GSD1/GSDT1/HLFT1	0.83	-	-	-
OS2	-	0.00114	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.98	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.92	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.95	-	-	-
SST1T	-	-	\$0.13	\$0.06
SST1D1/SST1D2/SST1D3	-	-	\$0.13	\$0.06
CILC D/CILC G	1.05	-	-	-
CILC T	1.01	-	-	-
MET	1.03	-	-	-
OL1/SL1/SL1M/PL1	-	0.00021	-	-
SL2/SL2M/GSCU1	-	0.00180	-	-

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

¹⁹RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months

²⁰SDD=((Total Capacity Costs)/(Projected Avg 12CP @gen)(21 on peak days)(demand loss expn. factor))/12 months

Table 33-3
FPL Capacity Cost Recovery Factors for the period January-December, 2018

Rate Schedule	2018 Indiantown Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00004	-	-
GS1/GST1	-	0.00004	-	-
GSD1/GSDT1/HLFT1	0.01	-	-	-
OS2	-	0.00003	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.01	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.01	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.01	-	-	-
SST1T	-	-	-	-
SST1D1/SST1D2/SST1D3	-	-	-	-
CILC D/CILC G	0.02	-	-	-
CILC T	0.02	-	-	-
MET	0.02	-	-	-
OL1/SL1/SL1M/PL1	-	0.00001	-	-
SL2/SL2M/GSCU1	-	0.00003	-	-

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

Table 33-4
FPL Capacity Cost Recovery Factors for the period January-December, 2018

Rate Schedule	2018 Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	Reservation Demand Charge (RDC) \$/kW	Sum of Daily Demand Charge (SDD) \$/kW
RS1/RTR1	-	0.00281	-	-
GS1/GST1	-	0.00263	-	-
GSD1/GSDT1/HLFT1	0.84	-	-	-
OS2	-	0.00117	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	0.99	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	0.93	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.96	-	-	-
SST1T	-	-	\$0.13	\$0.06
SST1D1/SST1D2/SST1D3	-	-	\$0.13	\$0.06
CILC D/CILC G	1.07	-	-	-
CILC T	1.03	-	-	-
MET	1.05	-	-	-
OL1/SL1/SL1M/PL1	-	0.00022	-	-
SL2/SL2M/GSCU1	-	0.00183	-	-

Source: Page 20 of 29 (Appendix V of Exhibit RBD-8)

GULF: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-5 below:

**Table 33-5
 GULF Capacity Cost Recovery Factors for the period January-December, 2018**

Rate Class	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW-month
RS, RSVP, RSTOU	0.835	-
GS	0.762	
GSD, GSDT, GSTOU	0.666	
LP, LPT	-	2.76
PX, PXT, RTP, SBS	0.560	-
OS-I/II	0.164	
OSIII	0.505	

Source: Schedule CCE-2, Page 40 of 41 (Exhibit CSB-6)

TECO: The appropriate capacity cost recovery factors for the period January 2018 through December 2018 are shown in Table 33-6 below:

**Table 33-6
 TECO Capacity Cost Recovery Factors for the period January-December, 2018**

Rate Class and Metering Voltage	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW
RS Secondary	0.066	-
GS and CS Secondary	0.060	
GSD, SBF Standard		
Secondary	-	0.20
Primary		0.20
Transmission		0.20
GSD Optional		
Secondary	0.047	-
Primary	0.047	
IS, SBI		
Primary	-	0.14
Transmission		0.14
LSI Secondary	0.016	-

Source: Document Number 1, Page 3 of 4 (Exhibit PAR-3)

ISSUE 34: What should be the effective date of the fuel adjustment factors and capacity cost recovery factors for billing purposes?

STIPULATION:

The new factors shall be effective beginning with the first billing cycle for January 2018 through the last billing cycle for December 2018. The first billing cycle may start before January 1, 2018, and the last cycle may be read after December 31, 2018, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

ISSUE 35: Should the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding?

STIPULATION:

Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct staff to verify that the revised tariffs are consistent with the Commission's decision.

ISSUE 36: Should this docket be closed?

STIPULATION:

No. While a separate docket number is assigned each year for administrative convenience this is a continuing docket and shall remain open.

HEDGING ISSUE STIPULATIONS

ISSUE 1A: Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2017 and August 2017 hedging reports?

STIPULATION:

Yes. DEF's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net expense of \$53,819,249 (\$53,953,024 expense for natural gas - \$133,774 gain on oil). Upon review of these filings, DEF has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

ISSUE 2A: Should the Commission approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in FPL's April 2017 and August 2017 hedging reports?

STIPULATION:

Yes. FPL's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net gain of \$9,334,634. Upon review of these filings, FPL has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

ISSUE 4A: Should the Commission approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in Gulf's April 2017 and August 2017 hedging reports?

STIPULATION:

Yes. Gulf's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net expense of \$29,478,936. Upon review of these filings, Gulf has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.

ISSUE 5A: Should the Commission approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in TECO's April 2017 and August 2017 hedging reports?

STIPULATION:

Yes. TECO's hedging activities for the period August 1, 2016 through July 31, 2017, are reported in April 2017 and August 2017 filings in Docket No. 20170001-EI and resulted in hedging net gain of \$1,361,535. Upon review of these filings, TECO has complied with its Risk Management Plan as approved by this Commission and, therefore, its actions are found to be reasonable and prudent.