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FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210001-EI

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

VOLUME 3

PAGES 247 - 459

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER ANDREW GILES FAY
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Tuesday, November 2, 2021

TIME: Commenced: 1:00 p.m.
Concluded: 4:36 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	318	318
2-67	As identified on the CEL	318	
49-67	As identified on the CEL		319
2-7	As identified on the CEL		319
10-48	As identified on the CEL		319
8-9	As identified on the CEL		451

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of Patrick A. Bokor was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

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

A. My name is Patrick A. Bokor. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Unit Commitment.

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

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have accumulated 15 years of experience in the electric industry, with experience in the areas of unit commitment and economic dispatch, power and gas trading, accounting, and risk management. In my current role, I am responsible for developing and implementing business plans and strategic initiatives to optimize business performance of Tampa

Electric’s generation. Specifically, I am responsible for directing short-term resource availability, preparation of the hourly, daily and weekend Unit Commitment Plan for review and approval by grid operations, fleet optimization, and overall operating and business performance.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor (“GPIF”) for the period January 2020 through December 2020. I will also compare these results to the targets established for the period.

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

A. Yes, I prepared Exhibit No. PAB-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Florida Public Service Commission (“FPSC” or “Commission”). Document No. 2 provides the company’s Actual Unit Performance Data for the 2020 period.

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

A. Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2020 through December 2020 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 25. Based upon 3.401 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $3,673,726 for the period.

Q. Please proceed with your review of the actual results for the January 2020 through December 2020 period.

A. On Document No. 1, page 3 of 25, the actual average common equity for the period is shown on line 14 as $3,387,268,691. This produces the maximum penalty or reward amount of $10,801,371 as shown on line 23.

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

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

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 25, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in Section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 25, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission’s Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 4

On this unit, 1,919 planned outage hours were originally scheduled for 2020. Actual outage activities required 3,262.2 planned outage hours. Consequently, the actual equivalent availability of 35.7 percent is adjusted to 47.0 percent, as shown on Document No. 1, page 7 of 25.

Polk Unit No. 1

On this unit, 744 planned outage hours were originally scheduled for 2020. Actual outage activities required 467.8 planned outage hours. Consequently, the actual equivalent availability of 69.6 percent is adjusted to 67.6 percent, as shown on Document No. 1, page 8 of 25.

Polk Unit No. 2

On this unit, 1,104 planned outage hours were originally scheduled for 2020. Actual outage activities required 246 planned outage hours. Consequently, the actual equivalent availability of 89.5 percent is adjusted to 80.4 percent, as shown on Document No. 1, page 9 of 25.

Bayside Unit No. 1

On this unit, 576 planned outage hours were originally scheduled for 2020. Actual outage activities required 673.8 planned outage hours. Consequently, the actual equivalent availability of 89.5 percent is adjusted to 90.5 percent, as shown on Document No. 1, page 10 of 25.

Bayside Unit No. 2

On this unit, 576 planned outage hours were originally scheduled for 2020. Actual outage activities required 381.3 planned outage hours. Consequently, the actual equivalent availability of 90.6 percent is adjusted to 88.5 percent, as shown on Document No. 1, page 11 of 25.

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

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 25, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 19 through 23 of 25. Page 4 of 25 summarizes the weighted equivalent availability points to be awarded or penalized.

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

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's five GPIF units are shown on Document No. 1, page 6 of 25. The adjustment was developed based on the guidelines of Section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 25, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 19 through 23 of 25. Page 4 of 25 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2020 through December 2020 period?

A. This is shown on Document No. 1, page 2 of 25. The weighting factors shown on page 4 of 25, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 25, column 4, are substituted within the equation found on page 25 of 25. The resulting value of 3.401 is located in the GPIF table on page 2 of 25, and the reward amount of $3,673,726 is calculated using linear interpolation.

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

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $10,801,371 as shown in Document No. 1, page 3.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

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

A. My name is Patrick A. Bokor. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Unit Commitment.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have over 15 years of experience in the electric industry, in the areas of unit commitment and economic dispatch, power and gas trading, accounting, and risk management. In my current role, I am responsible for developing and implementing business plans and strategic initiatives to optimize business performance of Tampa

Electric's generation. Specifically, I am responsible for directing short-term resource availability, preparation of the hourly, daily and weekend Unit Commitment Plan for review and approval by grid operations, fleet optimization, and overall operating and business performance.

Q. What is the purpose of your testimony?

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

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

A. Yes. Exhibit No. PAB-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2022 period.

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

A. Four natural gas combined cycle units and one coal unit are included. These are Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission’s approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2022 through December 2022 represent 82.6 percent of the total forecasted system net generation for this period.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, Big Bend Unit 4 and Polk Unit 1 outages were identified as outliers and were removed.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2022 period. A range of potential improvements and degradations were determined for each of these metrics.

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

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the five units included within the GPIF are shown on page 5 of Document

No. 1.

To give an example for the 2022 period, the projected EUOF for Big Bend Unit 4 is 16.2 percent, the POF is 12.1 percent. Therefore, the target EAF for Big Bend Unit 4 equals 71.7 percent or:

$$100\% - (16.2\% + 12.1\%) = 71.7\%$$

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

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

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

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

The factors included in the above equations are the same factors that determine the target equivalent availability. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Big Bend Unit 4 example:

$$EAF_{MAX} = 1 - [0.80\ (16.2\%) + 0.95\ (12.1\%)] = 75.6\%$$

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

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

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

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

Again, continuing using the Big Bend Unit 4 example,

$$EAF_{MIN} = 1 - [1.40\ (16.2\%) + 1.10\ (12.1\%)] = 64.0\%$$

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

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

A. The company's planned outages for January 2022 through December 2022 are shown on page 17 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2022; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for planned outages from April 1, 2022 to April 14, 2022 and from October 4, 2022 to November 2, 2022. There are 1,056 planned outage hours scheduled for the 2022 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 4 is 12.1 percent or:

$$\frac{1{,}056}{8{,}760} \times 100\% = 12.1\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 1.9 percent. Polk Unit 2 has a POF of 7.9 percent. Bayside Unit 1 has a POF of 20.3 percent, and Bayside Unit 2 has a POF of 3.8 percent.

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

A. Projected factors are based upon historical unit performance. For each unit, the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 16.2 percent for Big Bend Unit 4. The EUOF of Big Bend Unit 4 is verified by the data shown on page 12, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(673 + 747)}{8,760} \times 100\% = 16.2\%$$

Relative to Big Bend Unit 4, the EUOF of 16.2 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 10.3 percent. The unit will have one planned outage in 2022, and the POF is 1.9 percent. Therefore, the target equivalent availability for this unit is 87.7 percent.

Polk Unit 2

The projected EUOF for this unit is 2.7 percent. The unit will have two planned outages in 2022, and the POF is 7.9 percent. Therefore, the target equivalent availability for this unit is 89.3 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.4 percent. The unit will have one planned outage in 2022, and the POF is 20.3 percent. Therefore, the target equivalent availability for this unit is 77.4 percent.

Bayside Unit 2

The projected EUOF for this unit is 3.4 percent. The unit will have one planned outage in 2022, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 92.7 percent.

Big Bend Unit 4

The projected EUOF for this unit is 16.2 percent. The unit will have two planned outages in 2022, and the POF is 12.1 percent. Therefore, the target equivalent availability for this unit is 71.7 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 82.1 percent is shown on page 5 of Document No. 1.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 4 on page 12 of Document No. 1. Except for the months of April, October, and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of April, October, and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

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

Q. How were the targets determined?

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

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

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 25 through 29 of Document No. 1.

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

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2022 period.

A. The heat rate target for Polk Unit 1 is 8,855 Btu/Net kWh with a range of ±1,584 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,841 Btu/Net kWh with a range of ±923 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,339 Btu/Net kWh with a range of ±171 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,695 Btu/Net kWh with a range of ±276 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,726 Btu/Net kWh with a range of ±1,102 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission’s requirements?

A. Yes.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown in Document No. 1, pages 7 through 11. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $487,019,890 is shown on Document No. 1, page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

Column 4 totals $31,877,118 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Big Bend Unit 4, the weighting factor for average net operating heat rate is 11.18 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 7 of Document No. 1, if Big Bend Unit 4, operates at 9,624 average net operating heat rate, fuel savings would equal $3,563,326 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 11. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $31,877,118. The right-hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January 2022 through December 2022 is $4,108,620,276. This produces the maximum allowed jurisdictional incentive of $13,796,217 shown on line 21.

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

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $15,938,559.

Q. Please summarize your direct testimony.

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

$$GPIP = (0.0050\ EAP_{PK1} + 0.0501\ EAP_{PK2} + 0.0186\ EAP_{BAY1} + 0.0144\ EAP_{BAY2} + 0.0438\ EAP_{BB4} + 0.5247\ HRP_{PK2} + 0.0445\ HRP_{BAY1} + 0.1209\ HRP_{BAY2} + 0.1118\ HRP_{BB4} + 0.0662\ HRP_{PK1})$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January 2022 through December 2022 period?

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

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Benjamin F. Smith, II was inserted.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
FILED: 09/03/2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Origination within the Fuel and Planning Services Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida, and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student.

During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager, Gas and Power Origination within the Fuel and Planning Services Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion byproduct contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, other wholesale developers and independent power producers, as well as with natural gas pipeline owners and transporters.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I have testified before this Commission in Docket Nos. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

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

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

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

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

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

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order No. PSC-1997-0262-FOF-EI, issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the

Commission.

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

Q. Please describe Tampa Electric's 2021 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately 10 percent of the company's expected needs for 2021 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke Energy Florida ("DEF"), the Florida Municipal Power Agency ("FMPA"), Florida Power & Light ("FPL"), and the Orlando Utilities Commission ("OUC").

Presently, Tampa Electric has seven forward purchases applicable to the year 2021. Four of them have terms that carried over from 2020 as described in my 2020 testimony and summarized in the following bullet points.

- Three (3) firm peaking call options for the period December 2020 through February 2021: 160 MW from FPL, 100 MW from OUC, and 150 MW from FMPA. Ninety-five megawatts (95 MW) of the FMPA 150 MW were to meet the company's 20 percent firm reserve margin criteria during the 2021 winter season. The balance of the purchases was for economic reasons. The company secured these purchase agreements during the fourth quarter of 2019 at an estimated savings to customers (excluding the reliability portion of the FMPA purchase) of $325.6 thousand for 2021. These savings flowed through the company's optimization mechanism and benefited customers in accordance with the methodology approved by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017.

- A non-firm purchase from DEF, which was an extension of Tampa Electric's previous contract to purchase non-firm energy from DEF. The extension covered the period March 2020 through February 2021. The energy volume available under the contract remained at a maximum of 515 MW per hour. The DEF extension did not have a must-take obligation. The extension provided Tampa Electric the flexibility to schedule the energy when beneficial to customers. In February 2021, Tampa Electric and DEF extended the contract again for the period March through November 2021 and thus far, for the period January through July 2021, and thus far, the purchase has provided $1.4 million in projected savings to customers, which flow through the optimization mechanism.

The company's remaining three forward purchases are from OUC and FPL, executed in December 2020 and February 2021, respectively. A description of the purchases follows.

- A 200 MW, firm, peaking call option from OUC for the month of January 2021. The purchase was a reliability purchase to ensure energy service to customers in the event Tampa Electric experienced cold weather.

The purchase helped reduce the company's exposure to natural gas supply risk during its winter peak. Natural gas risks and mitigation are discussed in the testimony of Tampa Electric witness John C. Heisey, filed concurrently in this docket.

Two economy, non-firm, must-take energy purchases from FPL. Each purchase is for 150 MW. One covers the period March through November 2021. The other covers the period April through October 2021. The purchases provide a projected $3.4 million of savings to customers, which flow through the optimization mechanism.

Tampa Electric has not secured other forward purchases for 2021 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2022 and beyond?

A. Tampa Electric currently has no forward purchases for

2022. However, the company expects to incur capacity costs and has included them in its 2022 Capacity Cost Recovery Clause projection. The projected capacity clause costs total $5.9 million and support firm purchases for the Big Bend Modernization Project testing, if needed, as well as economic forward purchases. A further explanation of these transmission costs is below.

The final phase of the Big Bend Modernization Project construction occurs in 2022. Testing of the project's combined cycle operation will occur during the period July through October 2022, and the project team will periodically need operational control of the new Big Bend combustion turbines, Units 5 and 6, that will drive the combined cycle. Depending on key factors—such as projected load, unit availabilities, and planned maintenance—the company may purchase energy due to limited availability of the new Big Bend combustion turbines or the potential intermittency of their generation during times of combined cycle testing.

Tampa Electric included $3.1 million in its 2022 capacity clause costs for the cost of firm transmission purchases during the Big Bend Modernization Project test period, to secure the path for firm power products during the project's testing. The amount is based on 330 MW per month which equates to the size of one Big Bend combustion turbine, for the four months of July through October, at an assumed firm transmission rate of $ 2.35354/KW per month. Tampa Electric's transmission cost rate applied in this estimate is the current Florida Power & Light firm monthly point-to-point transmission rate.

Additionally, over the past several years, as noted previously with the economic purchases from FPL in 2021, Tampa Electric has identified forward, season-long economy energy purchases that produced savings for customers, and it expects to make such purchases again in 2022. While these agreements will be negotiated closer to the time they are needed, the company's projected transmission costs are based on recent history and market expectations. While Tampa Electric has yet to identify and secure economic purchase opportunities for 2022, the company included in its projection the dollars associated with these transmission costs.

The terms of the company's recent forward economy purchases were generally in the April through November timeframe and for about 300 MW. In 2022, the company will continue to identify and evaluate monthly and seasonal forward purchase opportunities that bring value to customers. Because 330 MW of transmission costs for Big Bend Modernization Project testing are already included for July through October, these additional transmission costs for economy purchases are for the months of April, May, June, and November only. The transmission costs for these months are estimated to be $2.8 million. This amount is based on the 300 MW per month for the four months at an assumed firm transmission rate of $ 2.35354/KW per month. The transmission cost rate applied in this estimate is the current Florida Power & Light firm monthly point-to-point transmission rate.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if appropriate, for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2021 and 2022.

A. Tampa Electric entered into various non-separated (*e.g.*, next-hour and next-day sales) wholesale sales in 2021, and the company anticipates making additional non-separated sales during the balance of 2021 and 2022. The gains from these sales are shared between Tampa Electric and its customers through the company's optimization mechanism.

Q. Please summarize your direct testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric’s energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of John C. Heisey was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

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

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position. I am responsible for all natural gas and power trading activities and work closely with the company's unit commitment team to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and all aspects of the Optimization Mechanism.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, the 2020 results of Tampa Electric's activities under the Optimization Mechanism, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. JCH-1, entitled Optimization Mechanism Results, was prepared under my direction and supervision. My exhibit shows the gains for each type of activity included in the Optimization Mechanism and the sharing of gains between customers and the company.

Q. Please provide an overview of the Optimization Mechanism.

A. The Optimization Mechanism is designed to create additional value for Tampa Electric's customers while also providing an incentive to the company if certain customer-value thresholds are achieved. The Optimization Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization.

Q. Please describe Tampa Electric's Optimization Mechanism submitted in Docket No. 20160160-EI and approved by Order No. PSC-2017-0456-S-EI.

A. Effective January 1, 2018, for the four-year period from 2018 through 2021, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customers.

Optimization Mechanism Transactions

Q. Please provide the details of Tampa Electric's short-term wholesale sales under the Optimization Mechanism for 2020.

A. Optimization Mechanism gains from wholesale sales were $422,867 or 6 percent of optimization gains for 2020. The monthly detail is shown in my exhibit in the schedule "Wholesale Sales-Table 3."

Q. Please provide the details of Tampa Electric's short-term wholesale purchases under the Optimization Mechanism for 2020.

A. Optimization Mechanism gains from wholesale purchases were $5,693,895 or 86 percent of optimization gains for 2020. The monthly detail can be found in my exhibit on the schedule labeled "Wholesale Purchases-Table 4."

Q. Please describe Tampa Electric's asset optimization activities and the gains from those transactions under the Optimization Mechanism for 2020.

A. Optimization Mechanism gains from asset optimization activities were $525,285 or 8 percent of optimization gains for 2020. The gains from asset optimization activities are shown in my exhibit at “Asset Optimization Detail-Table 5.”

A description of Tampa Electric’s 2020 asset optimization activities is provided below.

- Delivered solid fuel and or transportation capacity sales using existing transport - sell coal and coal transportation, using Tampa Electric’s existing coal and transportation capacity during periods when it is not needed to serve Tampa Electric’s native electric load;
- Asset Management Agreement ("AMA") - outsource optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to Tampa Electric.

Q. Please summarize the activities and results of the Optimization Mechanism for 2020.

A. Tampa Electric participated in the following Optimization Mechanism activities in 2020: wholesale power purchases and sales, delivered solid fuel sales, and natural gas storage AMAs. The optimization gains for 2020 were $6,642,047 which exceeded the $4,500,000 threshold by $2,142,047 as shown in my exhibit on schedule "Total Gains Threshold Schedule-Table 1." Customer benefits were $5,356,819, and company benefits were $1,285,228 in 2020.

Q. Did Tampa Electric incur incremental Optimization Mechanism costs during 2020?

A. Tampa Electric incurred incremental Optimization Mechanism personnel costs to establish processes and manage these new activities. However, the company agreed that it would not seek recovery of these costs through the Optimization Mechanism if it was approved and therefore has not separately tracked the costs.

Q. Overall, were Tampa Electric's activities under the Optimization Mechanism successful in 2020?

A. Yes, Tampa Electric produced customer gains of $5,356,819 in the third year of Optimization Mechanism activity. The company continues to focus on improvements in processes, reporting, and optimization strategies.

The southeast United States experienced mild winter weather again in 2020. Thus, most of the Optimization Mechanism gains in 2020 were generated in the spring, summer, and fall. Economic wholesale power purchases were the largest contributor of gains with 86 percent of optimization gains. Wholesale power sales gains were driven by above normal temperatures in March and October. Natural gas storage AMA gains were consistent throughout the year. Lastly, coal sales contributed solid fuel gains.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

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

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group, LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position. I am responsible for natural gas and power trading activities and work closely with the company’s unit commitment team to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and all aspects of the Optimization Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. JCH-2, entitled Tampa Electric Company’s Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2022.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. JCH-2 provides Tampa Electric’s overall plan for mitigating risk in the company’s procurement of fuel and purchased power during 2022.

Q. Is hedging activity included in Tampa Electric’s Risk Management Plan for 2022?

A. No. In accordance with the 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”), approved by Commission Order No. PSC-2017-456-S-EI issued on November 27, 2017, in Docket No. 20170210, the company agreed that it would not enter any new natural gas financial hedging contracts for fuel through December 31, 2022. Tampa Electric currently has no active natural gas hedges. In accordance with the 2017 Agreement, the company currently has no plans to engage in natural gas hedging activity.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210001-EI
FILED: 09/03/2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Origination and Trading.

Q. Have you previously filed testimony in Docket No. 20210001-EI?

A. Yes, I submitted direct testimony on April 2, 2021 and July 27, 2021.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. Yes. My position is Director, Origination and Trading, as of August 2021.

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

A. I am responsible for directing all activities associated with the procurement and delivery of energy commodities for Tampa Electric's generation fleet. Such activities include the trading, optimization, strategy, planning, origination, compliance and regulatory oversight of natural gas, power, coal, oil, byproducts, and associated delivery. I am also responsible for all aspects of the Optimization Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's generation portfolio includes natural gas, solar, coal, and, as a backup fuel, oil powered units. Big Bend Unit 2 operates on natural gas, and Big Bend Units 3 and 4 can operate on coal or natural gas.

Big Bend Modernization project's first phase, Big Bend combustion turbine Units 5 and 6, is expected to be in service in December 2021 and will operate on natural gas. The second phase of the Big Bend Modernization project includes the addition of the Heat Recovery Steam Generator ("HRSG") in December 2022 and will result in the unit's operation in combined cycle mode. Polk Unit 1 can operate on natural gas or a blend of petroleum coke and coal. Currently, the company is operating Big Bend Unit 2, Big Bend Unit 3, and Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.*, aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption is primarily for testing, and oil is a negligible percentage of system generation. Based upon the 2021 actual-estimate projections, the company expects 2021 total system generation, excluding purchased power, to be 85 percent natural gas, 7.5 percent solar, and 7.5 percent coal.

Likewise, in 2022, natural gas-fired and solar generation are expected to be 83 percent and 10 percent of total generation, respectively, with coal-fired generation making up 7 percent of total generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain many creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and flexibility to pursue lower cost options for Tampa Electric customers.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long- and short-term deliveries?

A. Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot and seasonal purchases. The contracts have various time lengths to help secure needed supply at competitive prices while maintaining the flexibility to adapt to any changing fuel needs. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. Tampa Electric targets natural gas supply that is reliable and resistant to the impacts of extreme weather. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage services to enhance access to natural gas supply during hurricanes, extreme weather or other events that constrain supply. Such actions improve the reliability and cost-effectiveness of the physical delivery of natural gas to the company’s power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices to mitigate costs for its customers.

Q. Please describe Tampa Electric’s diversified natural gas transportation agreements.

A. Tampa Electric currently receives natural gas directly via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric also receives a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline (via Gulfstream backhaul). The ability to deliver natural gas from three pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station from Gulfstream and Sabal Trail to support the station's steam generating units, aero-derivative combustion turbine, and upcoming Big Bend Modernization project. Later this year, the first phase of a new gas pipeline lateral will be completed that allows natural gas to be delivered to the Big Bend Station from FGT under certain conditions, such as a Gulfstream outage. This lateral increases the fuel delivery reliability for Big Bend Station. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Units 1 and 2.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric's natural gas usage is expected to remain steady in 2022. Though the additional solar generation and the retirement of Big Bend Unit 2 will result in a reduction in natural gas usage in the period, they will be offset by increased natural gas usage at the efficient Big Bend Modernization project. The strategy of burning economical natural gas in dual-fueled units continues to provide lower overall costs to customers.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama, and Southern Pines Energy Center in Eastern Mississippi to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in these two locations. This storage was used during Storm Uri in February 2021 to replace interrupted supply and to mitigate costs for our customers.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2, and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to potentially lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"), Gulf South pipeline ("Gulf South"), and Transco's Mobile Bay Lateral ("Transco"). SESH, Gulf South, and Transco connect the receipt points of FGT, Gulfstream, and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH, Gulf South, and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio. All receipt points in the portfolio are reviewed annually to ensure access to reliable supply basins.

Q. Has Tampa Electric acquired additional natural gas transportation for 2021 and 2022 due to greater use of natural gas?

A. Yes, with the company's growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal, and longer-term pipeline capacity to support the company's portfolio of gas-fired generation assets. In 2021, Tampa Electric acquired short-term capacity on FGT in January and February to increase the reliability of the portfolio for its projected winter peak. In addition, a power purchase was executed for January as a lower cost solution compared to acquiring additional short-term pipeline capacity, as mentioned in the testimony of Tampa Electric witness Benjamin F. Smith, II. In the summer of 2021, Tampa Electric acquired additional pipeline capacity on Sabal Trail. This capacity provides additional transportation for the portfolio as Tampa Electric continues to transition from coal-fired generation to cleaner burning natural gas-fired generation. For 2022, Tampa Electric modified and extended existing Gulf South transportation. As a contractual requirement at the end of 2022, Tampa Electric will replace its Sabal Trail capacity with Gulfstream capacity to supply the Big Bend Modernization project and other portfolio gas requirements.

Coal Supply Strategy

Q. Please describe Tampa Electric's solid fuel usage and procurement strategy.

A. Like its natural gas strategy, Tampa Electric uses a portfolio approach to coal procurement. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and are fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have been upgraded to operate on natural gas. Polk Unit 1 can burn a blend of petroleum coke and low sulfur coal, or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel's chemistry and contents vary based on many factors, including geography. The variability of the product dictates that Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal quality characteristics, price, availability, deliverability, and credit worthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generation stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market. This market intelligence also helps shape the company's coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2022.

A. Since the company is projected to use less coal and more natural gas in 2022 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts, and, as necessary, spot purchases in support of the most economic commitment and dispatch for the generation fleet. Short-term and spot purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes, and pricing opportunities.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements.

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1. As a result of declining solid fuel burns over the last few years, Tampa Electric now purchases delivered coal, where waterborne coal supply and transportation are arranged by the supplier. Procuring delivered waterborne coal continues to provide customers with competitive coal prices through a simplified process. Commodity and transportation of coal by rail is still being arranged separately, as necessary.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers various benefits. Those benefits include 1) access to more potential coal suppliers, which results in a more competitively priced, and diverse, delivered coal portfolio; 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode; and 3) competition among transporters for future solid fuel transportation contracts.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2021 and 2022?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2021 and is evaluating how much coal to receive by rail in 2022.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries.

A. Tampa Electric expects to receive solid fuel supply from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System or from foreign sources. The ultimate supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric's solid fuel transportation portfolio?

A. Yes. Tampa Electric continues to burn natural gas as the economic fuel in Big Bend Unit 3 and Polk Unit 1. Big Bend Unit 4 is projected to burn coal in 2022. In addition, the company's strategy of utilizing short-term and spot delivered solid fuel purchases allows Tampa Electric to maintain flexibility in its solid fuel portfolio while reducing solid fuel deliveries going forward, which aligns well with the economical use of natural gas. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and transportation in the remainder of 2021 and 2022 than in previous years.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long-term, intermediate, and short-term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Q. Are there any other pertinent aspects of how Tampa Electric manages its fuel supply portfolio?

A. Yes. As part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2022 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York

Mercantile Exchange ("NYMEX"), S&P Scenario Planning Service Annual Guidebook (originally produced by PIRA Energy Group), the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days ending in July 2021, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal commodity and transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as IHS Markit and Argus *Coal Daily*. Also, the price projections are specific to the quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2022 projected fuel prices compare to the fuel prices projected for 2021 in the company's mid-course correction filing?

A. Large quantities of domestic shale-related production are keeping natural gas prices relatively low. However, in 2021, demand outpaced supply as the post COVID-19 economic recovery drove domestic gas demand through increased LNG exports, increased natural gas exports to Mexico, and increased industrial demand. Strong gas demand from power generation early in the summer decreased storage inventory levels below the five-year average while gas production remained static. Natural gas prices started rising in the second half of 2021 and are expected to remain elevated through the first quarter of 2022 until increased production helps to balance the market. Additionally, there is uncertainty associated with natural gas prices for 2022 due to the ongoing pandemic.

The commodity price for natural gas during 2022 is projected to be slightly lower ($3.16 per MMBtu) than the 2021 price ($3.21 per MMBtu) projected in the company's mid-course correction fuel filing. The 2022 delivered coal price projection is slightly lower ($62.28 per ton) than the price projected for 2021 ($63.42 per ton) during preparation of the 2021 mid-course correction fuel clause factors.

Q. Does this conclude your direct testimony?

A. Yes.

CHAIRMAN CLARK: Let's move to exhibits.

MS. BROWNLESS: Thank you, sir.

Staff has compiled a stipulated Comprehensive Exhibit List, which includes the prefiled exhibits attached to the witnesses' testimony as well as Staff Exhibit 49 through 67. The list has been provided to the parties, the Commissioners and the court reporter.

At this time, Staff requests that the Comprehensive Exhibit List be marked for identification purposes as Exhibit No. 1, and that the other exhibits be marked for identification as set forth in the Comprehensive Exhibit List.

CHAIRMAN CLARK: So ordered.

(Whereupon, Exhibit Nos. 1-67 were marked for identification.)

MS. BROWNLESS: We would request that the Comprehensive Exhibit List, marked as Exhibit 1, be entered into the record.

CHAIRMAN CLARK: Exhibit No. 1 is entered.

(Whereupon, Exhibit No. 1 was received into evidence.)

MS. BROWNLESS: And we would request that the stipulated Staff Exhibits Nos. 49 through 67 be entered into the record.

CHAIRMAN CLARK: Number 49 through 67 are hereby entered.

(Whereupon, Exhibit Nos. 49-67 were received into evidence.)

MS. BROWNLESS: And finally, we would ask that the exhibits agreed to by the parties, Exhibits Nos. 2 through 7 and 10 through 48 be entered into the record.

CHAIRMAN CLARK: All the parties have had a chance to review the documents. Are there any objections?

Seeing none, they are entered into the record.

(Whereupon, Exhibit Nos. 2-7 & 10-48 were received into evidence.)

CHAIRMAN CLARK: All right. Opening statements. If the parties wish to make an opening statement they are going to be limited to three minutes each. Any of the parties plan to make an opening statement? Coming down the line. All right, let's just go through the list then.

All right. We will begin with Duke. Mr. Bernier.

MR. BERNIER: Thank you, Mr. Chairman.

Good afternoon, Commissioners. Matt Bernier on behalf of Duke Energy Florida.

As you have just heard, we have one issue remaining for your consideration, the prudence of DEF's operation of Crystal River Unit 4 as it pertains to an outage earlier year.

As Mr. Simpson demonstrates, DEF's actions leading up to the CR4 outage were prudent and DEF should be permitted to recover the replacement power costs incurred during the outage.

The outage was beyond DEF's reasonable control to prevent. The company's root cause analysis explains that the Beckwith Manual Sync Check Relay failed unbeknownst to the unit operator. That component is designed and intended to protect against the out-of-phase event that ultimately occurred. Had the normally reliable relay operated properly, the outage would not have occurred. Because DEF properly inspected and maintained the component and had appropriate training and operation procedures in place, DEF acted prudently at all times. Therefore we respectfully request recovery of all prudently incurred replacement power costs.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Bernier.

FPL.

MS. MONCADA: FPL waives and so does Gulf.
CHAIRMAN CLARK: All right.
MS. MONCADA: Thanks.
CHAIRMAN CLARK: FPUC.
MS. KEATING: FPUC waives.
CHAIRMAN CLARK: TECO.
MR. MEANS: We waive as well.
CHAIRMAN CLARK: OPC.
MS. PIRRELLO: Good afternoon, Commissioners, Anastacia Pirrello with the Office of Public Counsel.
We are here today to discuss a single issue, that of the prudence of Duke's actions in operation of the 712-megawatt Crystal River Unit 4 on the evening of December 17th, 2020, when they unsuccessfully tried to sync the plant to the grid. The resulting outage cost Duke's customers $14.4 million in replacement power costs.
Duke's actions were imprudent in that they failed to even meet their own internal procedures which were poorly communicated to a plant operator, who is poorly trained in a high pressure environment when Duke dispatch risked demanding generation resources to meet immediate load pressure.

You will hear testimony by Duke that attempts to pin the cost of this damage on a single individual while Duke's own root cause analysis is actually evidence of the management's inability to properly train the operator of a major generation facility or to provide clear and properly communicated procedures to critical operations crews in the face of supervisory staff layoffs.

After listening to the evidence and applying the long settled evidentiary standard that Duke has the burden of proof, and that its actions were prudent and as performed by a reasonable utility manager would have performed at the time, we believe you will agree that Duke's actions, both before and after the event, do not meet your expectations as the regulators for Duke's customers.

Duke's imprudence cost the customers millions of dollars, and it would be unjust to force those costs on to customers. Customers expect to be reimbursed for the cost of Duke's imprudence in a true-up once the damages have been accurately established.

Thank you.

CHAIRMAN CLARK: Thank you, Ms. Pirrello.

FIPUG.

MR. MOYLE: Thank you, Mr. Chairman.

And I have some brief opening comments I would like to make with respect to the Crystal River 4 unit, but before I do, I just wanted to thank the prehearing officer and the staff and all of the parties. These dockets present tons and tons of issues every year, and someone who is not close to it may not realize that; but through hard work, discussions, negotiations, we have been able to resolve them all with one exception. So I am going to spend a couple of minutes talking about the one exception that you will hear from a witness today, and I think -- I think it's important for a couple of reasons that this matter be brought before the Commission.

I believe that the issue before you, which is a prudence determination, is akin to a blocking and tackling duty responsibility of the Commission. Were the actions prudent or not? And we believe that they were not.

In talking to some fellow practitioners, I was asking, when's the last time that the Commission had a core prudence determination to decide? And the best that we could recall was it's been over a decade ago since you have had a prudence decision teed up like this.

You had the Bartow prudence decision that, because of a lot of confidential information, went over to DOAH and came back before you, but that decision was made by a DOAH administrative law judge. This decision is going to be made collectively by the Commission as to whether Duke was prudent or not.

And there is a little bit of a fine distinction there, because Duke has the burden. So they have to prove that they were prudent, and we don't believe they can do that based on the evidence in the case, particularly the root cause analysis.

I want to make one comparison by way of analogy. Engine turbines are the same turbines that fly jet airplanes, and turbines are a complicated piece of machinery. If you go on -- on a flight, oftentimes if the door is open to the cockpit, you see the pilots in there going through checklists and saying, yep, check, check, check, check. And checklists are a good procedural operation to use when you are flying an airplane. And I would submit that they are a good procedural device to use when operating a power plant.

And you will see that in this case, there are two units. And the exhibit that's attached to Mr. Simpson's testimony, JS-1 on page 51, it says a generize synchronization guide operator aid for Unit 5 is laminated and attached to the generator synchronization panel. So they had a checklist on No. 5, but on No. 4, it says, a laminated generation synchronizing guide, synchronization guide operator did not exist for Unit 4.

We think that's a strong piece of evidence that if there was a piece of paper up there saying, here's what you do, more likely than not, they would have done it the right way. They didn't have that piece of paper up there. They didn't follow the proper sequence, and we think that underlies their claim that they acted prudently.

So thank you for the chance to share some opening thoughts.

CHAIRMAN CLARK: Thank you, Mr. Moyle.

FRF.

MR. WRIGHT: Thank you, Mr. Chairman. Schef Wright, very briefly.

We -- the Retail Federation agrees with the positions of our consumer party colleagues that

Duke's actions were demonstrably imprudent and that recovery should be borne -- well, should not be had from their customers, and that Duke should -- Duke should bear the cost of their mistakes.

Thank you.

CHAIRMAN CLARK: Thank you.

Mr. Brew.

MR. BREW: Thank you, Mr. Chairman.

First, as a preliminary, I just want to reiterate our support for the resolution on Issue 110, which is the risk management plan; but with respect to CR4, the testimony in the root cause analysis are really troubling.

This is -- 712 megawatts is a very large generator. It's a very large piece of machinery. Synchronizing that generator to the grid is a basic function. Duke, in its RCA, or its testimony attempts to pin the blame basically on a failed relay, but the operative cause of the damage to the facility was caused by the operator, who manually override the process to force the relay closed that caused the generators sync inappropriately and cause extensive damage. So much damage, in fact, that it made the grid itself unstable and forced the Citrus 3 combined cycle unit miles away to shut down.

Going through the root cause analysis raises a bunch of issues that the Commission, I think, needs to focus on in terms of training and overall supervision by the Commission. And we don't that I Duke has remotely addressed its burden of proof to explain why those costs should be -- are reason and should be recovered.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Brew.

Nucor.

MR. LAVAGNA: Mr. Chairman, Nucor waives its opening statement.

CHAIRMAN CLARK: Thank you very much.

All right. Let's move to stipulated issues, Ms. Brownless.

MS. BROWNLESS: Yes, sir.

The Type 2 stipulations for DEF are 1A, 1B, 6 through 11, 16 through 22, 23A, 23B, 27 through 36.

For FPL/Gulf, they are 2A through 2J, 4A, 6 through 11, 16 through 22, 24A through 24D, 27 through 36.

For FPUC, they are 3A, 8 through 11, 18, 19, 20, 21, 22 and 34 through 36.

For TECO, they are 5A, 5B, 6 through 11, 16

through 22 and 27 through 36.
We would ask that there be a bench decision on these issues, and we are available to answer questions.
CHAIRMAN CLARK: Commissioners, do you have any questions on the stipulated issues?
Seeing no question, I will entertain a motion to approve the stipulation.
Commissioner Fay.
COMMISSIONER FAY: Mr. Chairman, I would move to approve 1A, 1B -- no, I am just kidding, just the issues as stated by Ms. Brownless here for all the Type 2 stipulations in front of us.
CHAIRMAN CLARK: I have a motion.
COMMISSIONER GRAHAM: Second.
CHAIRMAN CLARK: I have a second.
Any discussion on the motion.
All in favor say aye.
(Chorus of ayes.)
CHAIRMAN CLARK: Opposed?
(No response.)
CHAIRMAN CLARK: Motion carries.
All right. Let's get into witnesses.
MS. MONCADA: Mr. Chairman, before they call the first witness to the stand, I would like to ask

if FPL and the other parties whose stipulated issues have been approved may be excused.

CHAIRMAN CLARK: I think we --

MS. MONCADA: And I don't want to speak for the other attorneys but --

CHAIRMAN CLARK: You see they want to leave too? I am pretty sure most of those don't want to be here.

Yes, all of those parties who do have not have anything else to come before us may be excused.

MS. MONCADA: Thank you. I appreciate it.

CHAIRMAN CLARK: Thank you.

MR. MEANS: Thank you.

MR. BERNIER: This party sure died.

CHAIRMAN CLARK: I will give you a moment to -- we do have another -- Ms. Brownless, let me, just jumping ahead, we have an FPL/Gulf, FPUC issue.

MS. BROWNLESS: We do have Issue 1D, which is the issue for DEF, and we'll take care of that on next steps. That's a DEF issue.

CHAIRMAN CLARK: Okay. So there is nothing --

MS. BROWNLESS: Nothing for anybody else, no, sir.

CHAIRMAN CLARK: I am with you. I had -- I had a note here that -- I understand now. Much clearer now.

MS. BROWNLESS: Thank you.

MS. MONCADA: Thank you, Chairman.

CHAIRMAN CLARK: You are all excused.

All right. It is my understanding that Mr. Joseph Simpson will be testifying for us today. I want to remind our witnesses that their summaries are limited to three minutes, and I am going to ask Duke if they would call Mr. Simpson to the stand.

At the conclusion of Mr. Simpson's direct testimony, when DEF tenders him for cross-examination -- I am sorry, I got ahead of myself there.

Mr. Simpson, would you please stand and raise your right hand and repeat after me?

Whereupon,

JOSEPH SIMPSON

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do.

CHAIRMAN CLARK: Consider yourself sworn.

Mr. Bernier.

MR. BERNIER: Thank you, Mr. Chairman.

EXAMINATION

BY MR. BERNIER:

Q Mr. Simpson, will you please introduce yourself to the Commission and provide your address?

A Sure. My name is Joseph Simpson. I am the Manager of Regional Engineering for Duke Energy Florida. My business address is 8202 West Venable Street, Crystal River, Florida, 34429.

Q Thank you.

And you have just been sworn in, correct?

A That's correct.

Q Thank you.

Who do you work for, and what is your position?

A I am the Regional Engineering Manager for Duke Energy Florida, supporting the generating fleet across Florida.

Q Thank you.

And have you prefiled direct testimony and exhibits in this proceeding?

A Yes.

Q And do you have a copy of your prefiled testimony and exhibits with you today?

A I do.

Q Thank you.

Do you have any changes to make to your prefiled testimony and exhibits?

A Yes. There is one update, Exhibit JS-1, the date on the copy that it was provided was blank. The date that it was presented to the Regional Review Committee was March 11th, 2021. No other changes.

Q Thank you.

And if I asked you the same questions in your prefiled testimony today would you give the same answers that are included in your testimony?

A Yes.

MR. BERNIER: Mr. Chairman, we would ask that the prefiled testimony be entered into the record as if it was read today.

CHAIRMAN CLARK: So ordered.

(Whereupon, prefiled direct testimony of Joseph Simpson was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20210001-EI

DIRECT TESTIMONY OF JOSEPH SIMPSON

July 27, 2021

Q. Please state your name and business address.

A. My name is Joseph Simpson. My business address is 8202 W. Venable St. Crystal River, FL 34429.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Manager, Generation Engineering. DEF is a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Describe your responsibilities as Manager of Generation Engineering.

A. As Manager of Generation Engineering, I lead the Regional Engineering Organization for the Florida Generating Fleet. The group specifically provides engineering and technical support for components and equipment in the areas of electrical, instrumentation, control systems, and protective relaying. This department provides day-to-day plant support for maintenance and operations for planned/emergent work as well as project support during upgrades/modifications.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Electrical Engineering from the University of South Florida in Tampa, FL. I am a licensed Professional Engineer in the State of Florida, and I have 15 years of experience in power generation. Initially employed at Progress Energy Crystal River Unit 3 (“CR3”) Nuclear Facility as Instrumentation & Controls (“I&C”) Design Engineer. I transitioned later into Electrical/I&C Maintenance Leadership, Nuclear Operations, and then back to Design Engineering Leadership. Following closure of CR3 in 2013, I transitioned to non-nuclear generation as a Project Manager/Project Engineer. In 2016, I transitioned from Project Manager/Project Engineer into my current position as Regional Engineering Manager.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to present to the Commission the cause of the Spring outage at the Company’s Crystal River Unit 4 generating unit (“CR4”) and to explain how the Company acted reasonably and prudently at all times.

Q: Do you have any exhibits?

A: Yes, I sponsor the following exhibits:

- Exhibit No. __ (JS-1), Root Cause Analysis; and
- Exhibit No. __ (JS-2), Repair Evaluation Report.

These exhibits are true and accurate.

Q: Can you please give a summary of the CR4 Spring outage along with a high-level description of what caused the outage?

A: Yes. As CR4 was being returned to service after a planned outage, the unit attempted to synchronize to the grid out of phase, resulting in damage to the generator rotor and an unplanned outage. By way of background, generator synchronization is the process of connecting the generator to the 230kV transmission or power system (in the case of CR4) by matching the generator and power system's electrical parameter. During synchronization, the generator voltage and frequency are adjusted to match the system voltage and frequency, and the angle is monitored to ensure the breaker close circuit is completed when the angle "matches." Closely matching these parameters ensures torques are minimized as the power system begins to govern the prime mover's rotating field. Standard Operating Procedure ("SOP") at CR4 is to synchronize the unit to the grid in the automatic mode, that is to say, the command to close the generator breaker is given by a breaker control relay when the synchronization parameters are met. At many plants, SOP is to sync the unit to the grid manually, and the CR4 Startup Procedure not only permits manual synchronization but that method of synchronization has been used at CR4 both before and since this particular event.

In this particular instance, the CR4 operator unsuccessfully attempted three times to synchronize the unit in the “automatic” mode; after those attempts were unsuccessful, the operator green flagged the breaker (issued an “open” command to the breaker) and placed the sync switch in manual mode. The operator then red flagged breaker 3233 (issued a “closed” command to the breaker) expecting a failed synchronization which would allow repositioning of the sync switch handle back to automatic. The operator expected nothing to happen until the automatic sync option was selected and the synchroscope rolled to the twelve o'clock position. Unknown to the operator, the manual sync check relay (25) had failed, allowing the breaker close circuit to be completed causing the turbine/generator to attempt to sync to the grid out of phase.

Q: Has the Company performed a Root Cause Analysis (RCA) to understand the cause of the outage?

A: Yes. The Company’s RCA is attached to my testimony as Exhibit No. __ (JS-1).

Q: What is the purpose of the RCA?

A: RCAs are a standard practice when there is an event in the utility industry; for DEF, RCAs are required for events that meet the Safety, Environmental, Asset damage, or Megawatt impact (SEAM) criteria. Their sole purpose is to identify the cause of the event with the intent of preventing future similar issues from occurring. When an event like the outage being discussed occurs, DEF will perform an analysis to determine the cause(s) of the event, including contributory cause(s), the extent of the condition at the impacted unit and elsewhere within the organization, and determine what corrective actions can be taken to mitigate against repeat occurrences moving forward. Corrective actions could include, for example, modification, revisions, or creation of new procedures and/or training. The RCA attached to my testimony was conducted consistent with the Corrective Action Program for the purpose described above and was not done to support any regulatory proceeding.

Q: How many people were included on the RCA team and what were their backgrounds?

A: In addition to myself, the RCA Team included four (4) employees: a Generator Specialist from our Turbine Generator Services (TGS) Organization with 35+ years of generation experience, a qualified Operations Team Supervisor (OTS) from another facility in our Florida Generating Fleet, an OTS from CR4 that was not on-shift during the night of the event, and an Operational Excellence Specialist responsible for adherence to the Corrective Action Program.

Q: Please describe the result of the Company's RCA.

A: As shown in Section V of the Report (page 4), the RCA concluded there were two Root Causes of the occurrence: Failure of a component, specifically the Beckwith Manual sync check relay; and the previous success in use of a rule reinforced continued use of the rule. The RCA also determined there were other contributing causes, which are outlined in Section VI of the document.

Q: Can you please provide further explanation regarding the two root causes identified in the RCA?

A: Yes. The first cause identified was the failure of the Beckwith Manual sync check relay. The purpose of the relay is to prevent the generator/unit from attempting to sync to the grid in an out of phase condition – that is, its purpose is to prevent exactly what occurred at CR4. The Beckwith Manual sync check relay is a highly reliable component with extremely low known incidents of failure, so its failure was unforeseen and unforeseeable prior to the event. The second cause identified, the previous success of a rule reinforcing continued use of the rule, is essentially another way of saying the operator had previously performed a task in a certain way with no adverse consequences, and therefore believed it was acceptable to continue to do so without adverse results.

Q: Regarding the second identified cause, why was the operator not able to follow the rule in this particular instance without the unit being damaged?

A: The operator believed the generating unit would not be permitted to attempt to synchronize to the grid even though it was "red flagged" (the breaker commanded to close) because of the manual relay sync check; that is, the operator believed synchronization would be prevented by the device, thereby allowing the operator to reset the unit to "automatic" and proceed with synchronization attempt in automatic configuration. . Had the sync check relay not failed, this is the chain of events that would have occurred. However, because the relay check had failed, when the unit was "red flagged" it synchronized while out of phase causing the damage and the resulting outage.

Q: Was the operator's actions a result of a failure to properly train the operator?

A: No, the operator was properly trained and had the supporting materials necessary to correctly and safely operate the unit. In this case, the operator simply made a physical error by red-flagging (closing) the breaker approximately one (1) second prior to the appropriate time in reliance on the relay. In fact, had the operator closed the breaker one second later, no damage would have occurred (and the failure of the relay would have gone unnoticed until the next scheduled test or potentially the next attempt at manual synchronization). Thus, the failure was not of training, but was rather a human performance error. An explanation of what occurred and what led the operator to believe his actions were correct is summarized in the "Five (5) Why Staircase" on page 7 of the RCA:

1. Why did Crystal River Unit 4 generator have an out of phase synchronization to the grid?
1a. The operator red flagged the breaker at the wrong point in the synchronization process.

2. Why did the operator red flag the breaker at the wrong point in the synchronization process?
2a. The operator thought that it didn't matter when you red flagged the breaker.

3. Why did the operator think that it didn't matter when you red flagged the breaker?

3a. The operator understood that the synchronizing relay would not allow an out of phase synchronization.

4. Why did the operator understand that the synchronizing relay would not allow an out of phase synchronization?

4a. The operators training and experience supported this position.

4b. The operator expected the synchronization check relay to perform as designed.

5. Why did the synchronization check relay not support the operators training and experience, and not perform as designed?

5a. The synchronization check relay had failed allowing an out of phase event.

In sum, the operator believed it did not matter when he red-flagged the breaker because the sync check relay would not allow it to attempt to sync out of phase; had the component, which is a very reliable component that was properly maintained and inspected, operated as designed the operator would have been correct.

Q: Would the damage and resulting outage have occurred if the manual relay check had performed properly?

A: No. Notwithstanding any other actions taken by the operator, had the relay check performed as designed and expected, the unit would not have been able to attempt to sync to the grid out of phase and the unit would not have been damaged.

Q: What caused the relay to fail and should DEF have anticipated that failure?

A: No, DEF could not have reasonably anticipated the failure. The component was regularly tested in conformity with DEF's established testing protocol; in fact, it was tested approximately 6 months prior to this incident and was operating properly. However, at some time between the testing and the incident, a soldered component of the relay failed. My Exhibit No. __ (JS-2) is the Repair Evaluation Report provided by the component's manufacturer. There was absolutely no way for the operator to be aware of the failure. Had the unit synced to the grid in the automatic setting, or had the operator red-flagged the breaker within the range that would have allowed synchronization, DEF would still be unaware of the failure and would have remained unaware until either the next component test was completed or an operator attempted to manually sync the unit to the grid following a later outage – but in the latter case, only then if the operator mis-timed the synchronization attempt. DEF has prudently operated and maintained the relay check; the failure was beyond DEF's reasonable ability to control.

Q. Based on your review of the RCA, did DEF act prudently with respect to its operation of CR4?

A. Yes, as explained in my testimony, the Company at all times acted prudently.

Q. Does this conclude your testimony?

A. Yes.

BY MR. BERNIER:

Q And, Mr. Simpson, do you have a summary of your prefiled testimony?

A I do.

Q Will you please provide it?

A Sure.

Good afternoon, Commissioners. My name is Joe Simpson. I work with Duke Energy in the Regional Engineering organization. In this capacity, I lead the Regional Engineering organization and support the Florida generating fleet for technical support associated with electrical components, instrumentation components, control systems and protective relay. My testimony today demonstrates that the company acted prudently leading up to the spring 2021 outage at Crystal River 4.

Also sponsoring the root cause analysis of the event, which was produced by a team of experts in their respective fields to assist the company to fully understand what led to the out in hopes of preventing recurrence.

The root cause analysis determined that there were two primary causes associated with the event. The first was the unexpected failure of the Beckwith Manual Sync Check Relay, which is the protective device that's designed to prevent the generator from being allowed to synchronize out of phase to the grid.

The second was the operator attempted to reset the synchronization controls after the preceding auto sync attempt failed without the knowledge that the Beckwith Sync Check Relay had failed. Had the Beckwith Sync Check Relay not failed, the machine would not have been permitted to sync to the grid. The failure of the Beckwith was confirmed by the manufacturer as shown in Exhibit JS-2.

I look forward to answering any questions you might have. Thank you.

MR. BERNIER: Mr. Chairman, we will tender Mr. Simpson for cross.

CHAIRMAN CLARK: All right. Cross-examination order today will be OPC, FIPUG, FRF, PCS Phosphate, Nucor and then Staff. I don't know if everyone in that list has questions or not, but that's the order we will go in.

We will again with you, Ms. Pirrello.

MS. PIRRELLO: Thank you, Mr. Chairman.

EXAMINATION

BY MS. PIRRELLO:

Q Good afternoon, Mr. Simpson.

A Good afternoon.

Q He so you stated in your testimony that you are the Manager of Generation Engineering, correct?

A That's correct. I am sorry could you speak a little more loudly? I am having a hard time hearing you.

Q Yeah, that's fine.

You said the Manager of Generation Engineering, correct?

A That's correct.

Q And your department is responsible for supporting plant maintenance and operations?

A That's part of our responsible. Emergent issues as well as projects and upgrades.

Q Okay. So in December 2020, DEF was in the process of attempting to bring Crystal River -- Crystal River Units 4 and 5 back on-line after planned extended outages, right?

A Unit 4 was coming back from a planned outage.

Q So first you brought Unit 4 up to or near full power, right, on December 16th?

A December 16th, let me just check dates just to make sure I don't misspeak.

Q I believe it's in page 3 of the RCA, in that table.

A Yes, thank you.

Yes, Unit 4 was returned to service December 16th.

Q Okay. And then the next step was to bring the plant on-line by syncing it to the grid, right?

A So Unit 4 came on line December 16th, and then on December 17th at 19:10, it tripped due to boiler feed water control issues unrelated. So the next step following the trip was to return Unit 4 to service.

Q Okay. So isn't it true that you can't send power to the grid unless the grid -- or unless the generators are synced to it?

A That's correct.

Q So that's pretty important for the power supply, would you agree?

A Yes.

Q Okay. And ensuring that the synchronization is done correctly is important too?

A That's correct.

Q So you were going to bring Unit 5 up to full power separately from Unit 4 due to the fact that you could only use the one standby boiler feed pump which was common to the two units at one time?

A That's correct. There is only one startup or standby boiler feed bump, the electric driven pump, which is shared between the two units.

Q Okay. So in your testimony, at pages three and four, you describe a series of events that occurred in the unsuccessful attempt to sync Unit 4 to the grid, right?

A Correct. Let me just get to the testimony just so we are looking at the same thing. Okay.

Q And Duke performed a root cause analysis or RCA for this event, right?

A That's correct.

Q And you participated in the preparation of that document?

A That's correct.

Q And you testified that the purpose of that is to identify the cause or causes of the outage?

A To prevent -- or the purpose is it identify the cause of the event, not necessarily the outage.

Q Okay. But the RCA, in a generic sense, also has seller other benefits, right?

A Correct.

Q One is that you could try to determine if you have any case against a third-party, right?

A I am sorry, I am having a hard time hearing things.

Q One of the other benefits of a root cause analysis is that you could try to determine if the

company has any recourse against a third party, right?
A Not in this case.
Q No?
A No.
Q Okay. And a root cause analysis could also help identify if there was any intentional damage that occurred, right?
A Any potential, I am sorry?
Q Intentional.
A Oh, that's -- yes, it could.
Q Okay. And the final thing you may want to determine is if there is any corrective measures that should or could be undertaken to try to prevent the event from happening again, right?
A That's correct. We incorporate lessons learned from root causes to prevent recurrence.
Q So you also perform a root cause in order to contribute to the operating experience on a Duke Energy Corporation wide and on an industry wide basis, right?
A Correct.
Q And for this event, you performed RCA for OE purposes on a reciprocal basis because it benefits all the companies to share this information, right?
A That's correct.
Q And the RCA is the product of multiple drafts

and revisions, correct?

A Correct.

Q So before we get into the substance of it, on page two of the RCA, you list several root cause investigators?

A Uh-huh.

Q Could you match those people with the descriptions that you gave on page two of your -- oh, sorry, on page five of your testimony regarding the backgrounds of who was on the team?

A Sure.

Okay. So in the testimony at page five, beginning at nine, that's the question you are referring to?

Q Yes.

A Okay. So in the Exhibit JS-1, under the root cause investigators. Barbara Martinuzzi is the Senior Operating Excellent Specialist. As the title page indicates, she's also the preparer of the document. I am sorry, that crackling, I didn't know if it was me. So Barbara is the preparer, and she also ensures that we are in compliance with our corrective action program.

The next individual listed is James Winborg (ph) -- Jim Winborne. He is the turbine generation specialist, as noted greater than 35 experience in the generation field and industry. Myself. Doug Wood is the Electrical System Engineer at Crystal River Units 4 and 5.

I am just making sure I am mapping all the people both directions.

Gene Mullins, at the time he was an Interim Superintendent. That's why his title there is listed as Interim Superintendent. He has since then become a normal superintendent. He is no longer in an interim capacity. He is the other person that's mentioned as an Operations Team Supervisor from Crystal River Unit 4 that was not on shift during the night of the event. And that's page five, lines 14 and 15.

And then Dana Christensen, he is referred to as the Qualified Operations Team Supervisor from another facility in our generating fleet. And Dana is a Operations Team Supervisor at Citrus combined cycle.

Q All right. Thank you.

So the RCA reported that the cause of the outage was a relay that failed, right?

A The cause of the out-of-phase synchronization was -- that was the cause of the event, not the cause of the outage.

Q Okay.

A The cause of the outage was the generator damage.

Q Okay. So the cause of the failed synchronization was a relay that failed, is that correct?

A That's correct.

Q Could you explain to the Commission what a relay is?

A Sure.

A relay in this case, a specific relay is a synchronism check relay. As the generator is coming on-line, I have a generating source that is not connected to the infinite grid, and ensure -- and to ensure that the generator breaker in the middle closes at the proper time, this device looks at the electrical parameters of the generator, looks at the electrical parameters of the system, and when those match, it provides a permissive that would allow to the generator breaker to close.

Q Thank you.

And this is a piece of equipment that rarely, if ever, fails, right?

A That's correct.

Q And isn't it true that they -- there are no requirements to inspect or test this particular model of relay?

A There are no manufacturer stated requirements. However, we have company policies that provide periodic maintenance on this device.

Q And what is the maintenance interval that the company recommends?

A Six years is our non-NERC periodicity for protective devices.

Q So duke bought this relay in 2002, right?

A That's correct.

Q Can you tell the Commission where the rely was originally installed 20 years ago?

A Sure.

The Crystal River 4 substation, as the saga of Crystal River Entry Complex goes on, Crystal River Units 1 and 2 retired; Crystal River 3, of course, the nuclear facility is he gone, and there used to be multiple substations at the site. Since there are now only two generating facilities remaining with Crystal River Units 4 and 5, they have condensed that into a much smaller footprint, and the substation house is about 100 feet away from where the previous substation was, substation house. The substation is the same. The house is in the middle of the yard.

Q Which sub -- or that substation was associated with which unit?

A The current substation has consolidated the 230 kV and 500 kV. Previously, there were two separate houses. The Crystal River Units 1, 2 and 4 went to the 230 kV substation house. Unit 3 and Unit 5, which are connected to the 500 kV substation, were previously in the 500 kV substation. But since there is only one 500 kV breaker associated with the facility for Crystal River Unit 5, it's in a much smaller building.

Q Okay. Where was it installed 20 years ago, which unit?

A The two -- the previous, the old 230 kV house.

Q Okay. And you moved the relay from that unit to Unit 4 as part of the 2017 to 2019 upgrades, right?

A We moved it to the new 230 substation house, not to the Unit 4 generating facility.

Q Okay. So in response to staff's inquiries, you were only able to identify one instance in the first 18 years that this relay was tested, right?

A That's false.

Q If you could get Exhibit 54 and turn to your response to question 13A?

A Sure. Could you repeat that number? I am sorry.

Q 13A, it's on page five of these responses.

A Okay. That's the question begins with refer to page three of nine?

Q Page -- yes.

A Okay. Thank you.

Q And you responded that the relay was calibrated in 2011, 2014, '18 and 2020, correct?

A That's correct.

Q Okay.

A And we provided the previous four calibrations upon request.

Q Okay. And that reflects more frequent testing than your six-year timeline that you stated earlier. Is there a reason for that?

A When a generating facility is off-line and outage schedules, they vary, sometimes 18 months, sometimes 24 months, but if you have the opportunity and the unit is off-line, it's never a bad thing to test more frequently.

So depending on outage schedules and the resource availability, they were tested multiple times, much more than the manufacturer would recommend -- I am sorry, much more than NERC would recommend or require.

I do want to make the distinction that this is not a NERC device. It does not enter any flow to the bulk electric system. It's a blocking relay to protect the unit from coming on-line.

Q Okay. So in the spring of 2019, the relay was moved to serve the new substation, right?
A Correct.
Q And then in April, a functional test was run, which involves testing the whole unit, correct?
A Correct.
Q So if we could turn to Exhibit 64 on the CEL. It's also provided as OPC cross Exhibit 1 if that's easier for you to find.
A I am sorry, could you help me with the document number?
Q Document CE -- or CEL document 64. It's a supplemental response to Citizens' First Request to Produce Documents.
A You have to pardon my ignorance on the document numbering systems.
Q That's all right.
A And one more time, I am sorry, the --
Q The Bates page --
A The Bates page, that might help me more. Thank you for --
Q Yeah, 228.
A Okay. Okay. And that's Bates page DEF-000228?
Q Yes.

A Okay. Thank you.

Q So on that page, under the heading, Extent of Condition, the first paragraph last sentence says, quote, as of this writing, two bad boards and manual contacts failed closed have been discovered; is that right?

A That's what the document states.

Q Turning back to your root cause analysis, page five.

A Okay.

Q So it says there, under the heading, Repeat Event Review, that there have been no failures of this item at any of the Florida fleet within Duke; is that right?

A Correct.

Q And then going back to the document we had a second ago, Exhibit 64 on Bates page 230.

A Okay.

Q So someone here appears to -- somebody on the RCA team appears to have raised a question about the repeat events. Can you read the handwritten notation under the heading Repeat Event Review to the best of your ability?

A Penmanship is poor, and I say that because it's my handwriting, as evidenced by the fact that I can't make out the last word.

It says: Should we maintain the pulverizer good catch -- oh, should we mention the pulverizer good catch. Yes, that's what it states. I am sorry. Should we maintain the pulverizer good catch.

Q And isn't it true that the mentioning of the pulverizer did not make it into the final RCA?

A That's correct.

Q And isn't it true that the manufacturer cautions against changing anything about the installed relay component?

A That's correct.

Q A relay of equivalent specifications would cost no more than about $10,000, would it?

A Correct.

Q But probably more likely to be around 6,000 to 7,000, somewhere in that range?

A Seems fair, but I don't have a manufacturer quote on the device in front of me.

Q Okay. So rather than purchasing a new one, you salvaged the nearly 20-year-old relay from another station and installed it in the then current location in 2019, and about a year about installing it you decided to test the unit, and then eight months after that the relay failed; is that timeline right?

A Not entirely. And the description that it was salvaged I also take exception to.

So the relay was purchased and in service, then as it was tested successfully multiple times for many years, there wasn't a need to replace something just for the sake of replacing a working piece of equipment.

So salvaged, I would state as repurposed, because it's still performing the same function of preventing breakers 3233 and 3234 from closing. So if you could imagine, we moved it from one relay rack another relay rack a device that had been tested and working for many years.

Q In April of 2020, did Duke functionally test all of the relays system-wide?

A In what year? I am sorry.

Q In April of 2020, when the functional test was --

A Yes, as part of the recommissioning of the substation breakers 3233 and 3234, the breakers were replaced in their entirety. So all the breaker control circuits, all the protection circuits in all of the devices were tested through relay functional checks as well as actual performance tests as the unit came on line multiple times over the next approximately 18 months.

Q Okay. If we could go back to the 2017 to 2019 modifications in your RCA.

A In the draft documents, or are you back to the --

Q In the final version.

A Okay.

Q I am looking at page three of the RCA, which is also Bates 50.

A Bates 50?

Q Yes.

A Okay.

Q So under the heading Extent of Condition, again, this event, the 2017 to '19 modifications are referred to a few different ways, wouldn't you agree?

A Referred to a few different ways, I am not -- I am not sure I follow.

Q Well, in the first paragraph under this heading there is a reference to, quote, 2017 to '19 fiberoptic communication upgrade, right?

A Right. That's part of the breaker upgrade.

Q Okay. And then in the third paragraph there is a reference stating, quote, relay panels were modified during 2017 and completed in 2019 as part of transmission substation upgrade project, unquote, right?

A Correct.

Q And then the fourth paragraph there is a reference to, quote, 2017 to 2019 fiberoptic outage, unquote, right?

A Uh-huh.

Q So -- and then finally, under the Analysis heading on that same page, there is a reference to, quote, configuration changes occurring between 2017 and 20, unquote --

A Uh-huh.

Q -- right?

A I agree.

Q So is it true that the reader of the RCA should infer from the overall context that these four somewhat differing descriptive phrases are nevertheless all referring to a single overall upgrade project?

A It's a phased upgrade of the entire substation that took place over several years. So the breakers were upgraded. The communications were upgraded. So it, in effect, both 230 kV as well as the 500 during that period.

Q Okay. But it's just one project that occurred through several phases, correct?

A Yes, one, from a capital dollars perspective, one project that is executed over several years in phases.

Q Okay. So for the purposes of our questioning today, can we agree to refer to this as the upgrade project?

A Sure.

Q Okay. Could you tell the Commission what modifications were made in the upgrade project as they relate to the events that led to the forced outage at Unit 4?

A Sure. The primary driver was to replace the generator breakers, breakers 3233 and 3234, with high speed breakers. So these breakers open in three to five cycles, and they are SF6 type breakers. So the breaker replacement was part of the modernization of the Crystal River substation.

Additionally, if you were to look at the physical distance between the control room and the substation, it's on the order of about a mile-and-a-half roughly. And those circuits used to be copper circuits, and so cables were pulled in the early 1980s, and they provided the communication between the substation breaker controls and the control room. That was converted to a fiberoptic data link, a much more modern way to communicate between remote locations.

And the Crystal River -- so that's the 230 part. Crystal River Unit 5, as I mentioned before, with the retirement of Crystal River 3, that footprint which was six 500 kV breakers was reduced to a single 500 kV breaker in that period.

Q And could you explain why you referred to the upgrade project as an outage?

A The unit is unavailable while the breakers are being replaced. The unit -- unit outage is required to perform those upgrades.

Q Okay. On that same page, page three of your final RCA, in the second paragraph toward the top of the page, you state, quote, no damage was initially found to the machine during the inspection. All electrical tests were satisfied and the station went into a forced outage. Did I read that right?

A Yes.

Q And isn't it true that the sentence we just read refers to your initial evaluation on or about December 17th?

A That's correct.

Q And going back to page two, the next to last sentence on that page --

A Page two of the same document?

Q Yes.

A Okay.

Q So the next to last sentence on that page, starting with this, would you read that aloud?

A The next to the last sentence -- oh, this resulted?

Q Yes.

A Okay. This resulted in significant damage to the generator rotor. The event also caused enough grid disability on the 230 kV system to trip Citrus Power Block 1 station off-line.

Q Thank you.

Going back to page three, the second paragraph, second sentence, would you read that one for me?

A I am sorry, page three, second --

Q Second paragraph, second sentence, starting with during?

A Okay. During attempted startup on January 7th, a low speed centrifugal found -- centrifugal ground was found on the main generator field and unit was placed in a forced outage.

Q And isn't it true that the low speed centrifugal ground reference and significant damage to the generator rotor reference are referring to the same damage?

A I am sorry, I couldn't hear you real well.

Q Okay. So we read on page two there was a citation of significant damage to the generator rotor, and then on page three low speed centrifugal ground was found, is that referring to the same damage?

A It is.

Q And all of that damage was discovered on January 7th, 2021, correct?

A That's correct.

Q You would agree, subject to check, that the number of days between December 17th and January 7th is 21 days?

A Subject to check, sure.

Q Okay. Could you point to me in your Exhibit JS-1 of the RCA where you explain why 21 days passed before you discovered the low speed centrifugal ground damage to the generator rotor?

A Sure. The unit was placed after we did the initial electrical testing, the unit was not in demand by the system, so there was no call for the unit to come on-line during that, subject to check, 21-day period. There was -- it was not an economic dispatch until we attempted to bring the unit back on the 7th of January.

Q So if you could go to Exhibit 54, Staff's Fifth Set of Interrogatories, your response to Interrogatory 13D, which is on page six.

MR. BERNIER: I am sorry, was that 54 or 64?
MS. PIRRELLO: 54.
MR. BERNIER: Thank you.
THE WITNESS: Can you he help me with the Bates number? I am sorry.
BY MS. PIRRELLO:
Q There is no Bates number. It's page six of that document.
A Oh, okay.
Q Are you there?
A I am.
Q Could you read for me the date that the unit was brought back into service?
A Return to economic dispatch?
Q Yes.
A March 25th.
Q Okay. And so in total, again subject to check, the outage lasted about 98 days, is that right?
A Approximately.
Q Okay.
A The forced outage lasted that long.
Q Okay. Thank you.
And isn't it true that your failure to discover the damage for 21 days prolonged the forced outage by that same amount of time?

A A centrifugal ground cannot be detected with the unit at zero speed. So when you -- going back to -- I am sorry, I don't want to lose my page -- going back to the initial electrical testing that's on the stator, and that's on the transformers and that's on the generator terminal side.

The generator rotor, which is the rotating assembly attached to the prime mover, a steam turbine in this case, until you bring the unit back up to speed and you flash the field, you don't know that you have a ground.

So all of the initial testing at zero speed, which included the generator rotor, tested at zero speed through insulation resistance testing did not indicate any ground that was present. Until the unit is brought up to speed, you don't know that that fault condition exists. And the next time the unit was dispatched in early January, that was the first time the unit was at nonzero speed in which it could be sensed or detected.

Q Okay. So you were trying to bring the unit up into service on December 17th, and then when that was not successful, you stated that there was no demand for that unit for another 21 days?

A We took -- after the fault event, we knew we had to do testing. Following that event, we are not going to return that unit to service with the potential for stator damage or rotor damage. So the unit -- and I think the RCA might state what day, but that testing takes about, I remember about seven to eight days roughly.

So event happens on the 17th. We take the unit out of the possibility of dispatch because it's in a forced outage for electrical testing. The testing takes approximately seven to eight days, and at that point, there is no demand until January 7th. So 10-ish days, roughly, between Christmas and January 7th, 12 days, somewhere like that.

Q All right. So after that testing was finished was when you tried to bring the plant on-line again and you discovered the damage to the ground?

A That's incorrect.

Q No?

A After the testing, the unit was placed into reserve shutdown or not in demand based on it was out of economic dispatch. So there was no appetite to bring the unit on. There was no demand on the system to bring it back until January 7th.

So the status changed from December 17th until roughly December 23rd, subject to check, that the unit was in a forced outage. It then transitioned into a not-in-demand period, from December 23rd, roughly, until January 7th.

Q Okay.

A I think those dates are called out in the root cause document.

Q Was the unit available during that time?

A During the period of, that it was not in demand?

Q Yes.

A It was placed in a not-in-demand status, which meant that if asked, we would bring the unit up.

Q So you were capable of bringing it up during that time --

A Correct.

Q -- as far as you understood?

A As far as we knew.

Q Okay.

A So had they called on us to bring the unit on-line, we would have learned on, say, Christmas, December 25th, what we learned on January 7th. But since the unit was not called upon to return to service, it was not knowable.

Q Okay. And isn't it true that the replacement power costs for this outage were $14.4 million?

A I don't know the answer to that.

Q That's in Exhibit 67.
A Okay.
Q Now, there is no Bates on these. It's page two of that document, the response to 5B.
A In response to 5B. I am sorry, one more time with the name of the document.
Q It's CEL Exhibit 67, which is also Duke's Responses to Staff's Fourth Set of Interrogatories.
A Fourth set.
MR. BERNIER: Mr. Simpson, I think it's Tab 15 in your notebook the way it's set up.
THE WITNESS: Tab 15?
MR. BERNIER: I think so.
THE WITNESS: I only go to 10.
MR. BERNIER: Okay. We would be willing to stipulate to the amount that in the discovery --
THE WITNESS: Yeah, I apologize. I don't have intimate knowledge of the cost calculations for replacement power.
MS. PIRRELLO: That's okay. Thank you.
MR. BERNIER: No problem.
BY MS. PIRRELLO:
Q So going back to the RCA and turning to the second cause that you guys discussed.
A Sure. Now the root causes or contributing

causes?

Q Root cause.

A Okay.

Q So the second root cause you referred to in your narrative testimony is a human performance error, and you explained that the other cause was the timing of the operator's actions in trying to sync to the grid; is that right?

A That's incorrect. He was not attempting to sync to the grid. He was attempting to reset the synchronization circuit so he could get back to level set to attempt an auto synchronization.

Q Okay. But his timing in that attempt is the second root cause?

A That's correct.

Q Okay. Was this operator an employee or an independent contractor on December 17th, 2020?

A Employee.

Q In your testimony on page three, line 22 through 24.

A The direct testimony?

Q Yes.

A Okay. And I am sorry, the page?

Q Page three, lines 22 through 24.

A Okay.

Q So you stated that the startup procedure for CR4 has permitted manual synchronization both before and after this outage events, is that right?
A That's correct.
Q But prior to 2017, manual synchronization was actually the preferred method of syncing the generator to the grid, or of synchronizing as you described?
A That's correct.
Q Okay. So is it fair to say that since 2019, the use of manual synchronization has been rare?
A Yes.
Q On the next page, or I am sorry, on the RCA, page four.
A Let me just clarify, rare is a bit subjective, and I don't have a count as to how many times it was manually synchronized versus automatically synchronized. So the preferred method may have been auto, but there is no procedural reason that they can't use manual at their discretion.
I am sorry, I broke your rhythm on your question.
Q That's okay.
If you could go back actually to page two of the RCA.
A Sure.

Q In that last paragraph in the middle, it says, quote --
A Slow down. Slow down.
Q Good?
A Yeah.
Q So it says there, quote, through interviews, it was noted that the auto sync option has been used since 2017 and use of the manual option would be rare, correct?
A Correct.
Q So that is how your team characterized it as rare?
A True.
Q Okay. So then going back to the page four of your RCA --
A Okay.
Q -- under the contributing causes, the team found that one of them was, quote, practice or hands-on experience LTA. Can you tell me what LTA means?
A Less than adequate.
Q And you are responses to Staff's Interrogatories No. 11, which is CEL 54 that we have been looking at, it says that this operator had been working in the utility industry since 2006, is that right?

A That's incorrect. He has been working in the industry since 2001. He has been an operator since, his training records indicate, 2006.

Q Isn't it true that you didn't state in this response that he started in the industry in 2001, so on page two of the responses?

A So the question was power plant operations. So we addressed his experience as a power plant operator. Prior to that, he was a laborer and building serviceman, so still working in power generation but not an operator in the facility.

Q Okay. So he has been an operator since 2006?

A That's correct.

Q Okay. And would you consider someone who has been working as an operator for 15 years, give or take, to be reasonably experienced?

A Yes.

Q So in the root cause analysis you have this five why staircase. It's on page seven. And No. 2A there, it says, quote, the operator thought that it didn't matter when you red-flagged the breaker, unquote. Am I reading that right?

A That's correct.

Q So in your testimony on page seven, lines five through six, it says -- I will give you a second.

A I am running out of fingers and toes to place-hold.

Q That's all right.

A What was -- what was the reference?

Q Page seven of your testimony.

A The direct testimony?

Q Yes.

A Okay.

Q So it says on that page that the operator red-flagged the breaker one second too soon.

A Uh-huh.

Q If one second is the difference between successful synchronization and damage to the generator and the tripping of another one, why would someone with 15 years of experience think that it didn't matter when you did that?

A So your statement disregards the protective circuit behind that operator action. The -- the process of selecting the breaker to the closed position when you have a protective device behind that, that's what the statement it doesn't matter means is your protective device is there if you are early.

So with a working Beckwith device, you can be a minute early and the event will not occur. Unbeknownst to the operator, a device that's a mile-and-a-half away from him at the site when he takes the control switch and turns it to the red flag or closed position, that was the one second too early. So had the device been working, and he had been one second later, the unit would have likely synchronized in manual with no problem.

Now -- so that's -- that's the portion of your statement where, if he is early and the device is functioning, then it doesn't matter, because you can be early and your protective device performs its function and the breaker does not close until the parameters are met.

Q So of that device functions as sort of a safety net for the operator?

A It's a protective device.

Q Okay. Back to your response to question 11 on page two of Exhibit 54.

A I am sorry, question?

Q 11.

A That's page two?

Q Yes.

A Gotcha.

Q So it says that the operator briefly left Duke Energy Florida and was working for another utility company from 2013 to 2017, right?

A 2013 to 2017 he was not employed by Duke Energy.

Q Okay. And in this same set of responses to Staff, you produced a table in response to question 11B regarding the operator's training history.

A Uh-huh.

Q And this shows all of the training that they received while they worked for the company, is that right?

A That's correct. That's an export from the training program document or tool.

Q Okay. And all of the trainings that may have included generator operation and synchronization are highlighted, right?

A That's correct. I am sorry, let me just get to that document so we are -- in case you ask any specific questions I want to make sure I am there. Okay.

Yes. The green indicates that it's associated with generator operation.

Q But you are not certain that any of these trainings actually did include generator operation and synchronization, is that right?

A The course descriptions are associated with generator operation. So I wasn't present in every training class he has taken over the last 15 years to know the exact lesson plans, but by the training descriptions those are associated with generator operation.

Q If you flip back to your narrative response to 11B.

A Okay.

Q Could you read the second sentence under that response?

A Trainings which have included?

Q Yes. Actually if you could read from there through the rest of that response.

A Sure.

Trainings which may have included -- oh, I am sorry -- trainings which may have included generator operation and synchronization are highlighted. There is not a specific course for generator synchronization. On-the-job training is not specifically documented nor are simulator sessions.

Q And nothing in the RCA demonstrates that such training occurred, does it?

A We did not document any training history other than he is a qualified experienced journeyman as part of the root cause.

Q Okay.

A Journeyman operator, I should be clear. I am sorry.

Q That's all right.

So on Bates page 85 in that table.

A Okay.

Q The first highlighted entry after the operator returned to DEF is on August 8th, 2020, right?

A Which Bates page?

Q The highlighted entries on Bates page 85.

A Okay.

Q If you go back to Bates page 82, it shows 2013 and then cuts to 2017. So that's where I am looking from, from 82 through Bates page 85, the first highlighted entry.

A Right.

Q And that's on August 8th, is that correct?

A There are two other courses on Bates page 85 that are highlighted associated with combined cycle operations instructor led courses.

Q Okay. Those ones in February, is that right?

A February 19th.

Q Okay. So this operator left the company, and then upon their return, and after all the configuration modifications made during the upgrade project, they didn't receive any training on generator synchronization

until February of 2020, almost three years after they may have returned depending on when in 2017 they came back?

A Based on the training record, which are classroom activities, again on-the-job training, and simulator sessions are not included in here, the documented training timeline that he stated is consistent with the training program export.

Q Okay.

A Just of note, during that period, his Duke Energy hiatus, he was a supervisor with two other Florida utilities performing the same steps and activities on similar boilers and generators. So he was trained performing all of those activities during that period as well.

Q Okay. And isn't it true that you didn't present any evidence demonstrating that you looked at the training records and specifically determined whether there was training on syncing Unit 4 and 5?

A That's correct. Many of these courses are retired. The course material from 15 years ago is not something with a short turnaround to meet the staff's answers that we could pull of training course syllabus back 15 years in a short turnaround.

Q Did you do that analysis for these three

trainings that are listed in 2020?

A No, ma'am.

Q Okay. And around 2019, the end of the upgrade project is when you formally changed to the plant line relay panel light sequence, right?

A That's correct.

Q If we could go back to the RCA, page three.

A Okay.

Q The third paragraph under the heading Extent of Condition starting with the plant could you read that whole paragraph aloud please?

A Third paragraph?

Q Yes.

A The plant line lockout, 3 Alpha Golf and Alpha Bravo, relay panels modified during 2017 and completed in 2019 as part of transmission substation upgrade project, making Units 4 and 5 panel light sequences and visual cues identical. Before this strong, the plant line replay panel sequence, which indicates a unit trip, was different for both units. Operations Team Supervisor was aware of this modification, but several operators on the shift were not and did not check the plant line relay panels on the initial walkdown. Detailed information on the relay trip schedules, along with the lockout relay reset procedure would have

assisted operations during multiple attempts to
synchronize.

Q Thank you.

And nothing in the RCA demonstrates that this operator was told of this change in the training, does it?

A I am sorry, could you ask that again?

Q There is nothing in this RCA that says that the operator was told of this change in a training course, right?

A There was no documented -- we would call them acquired reading or shift log, or anything like that.

Q And so there is also no documentation that the operator was told of this change through any other means of communication, right?

A No documented information.

Q All right. But had you discovered that they had been told about this, you would have included that in the RCA, correct?

A Had we discovered -- I am sorry, can you rephrase that?

Q So the RCA discusses some interviews and that sort of thing. If you had any evidence that this operator was specifically told of this change, you would have put that in here, is that right?

A That's correct.

Q Okay. And the RCA found that the OTS did not inform all of the operators to the change to the relay panel light sequence, correct?

A The specific operations team supervisor that was on duty that night. So bear in mind, there is five that rotate through with rotating crews. So we -- they change crews from time to time as well. So this specific supervisor, he was aware of it, but this particular operator on that crew was not.

Q Okay. Thanks.

A And just a note there, in the follow-up questions, there is of a picture that shows the laminated information that's affixed to those panels, so it's -- it's readily available for operators to talk about of that light sequence and the reset sequence. So there may not have been a documented training, but the instructions were affixed to the panel that they reset.

Q Okay. If you could go to page six of the final RCA.

A Okay.

Q Would you read out loud the first box under corrective action beginning with ensure?

A Under the top table?

Q Yes.

A Okay. Ensure that a -- ensure that there is a specific lesson plan around generator synchronization and implement.

Q So at the time of this failed synchronization and the resulting outage there was no specifically training on generator synchronization at all?

A So the statement of the word ensure is different than verify. So ensure was to go validate that it's there and go execute that, or implement that to all the crews that were there. So it would have been a refresher type training.

Q Okay. Going back to page four and five, where it lists the contributing causes.

A Page four and five, okay.

Q So there are multiple contributing causes listed here, is that right?

A That's correct.

Q So for each one of these, could you go through and read aloud the small italicized sentence under the heading for the first one, and then pause and we will continue through those?

A For each of the contributing causes?

Q Yeah, if you could reach read the first one and then I will have a question, and then we can go through the rest of them.

A Okay. So beginning with contributing cause, Alpha 3 Bravo 3 Charlie 04, less than adequate review based on assumption that process will not change. In the parenthesized -- I don't if that's a word but I just said it -- individual believed that no variability existed in the process and thus overlooked the fact that a change had occurred leading to different results than normally realized.

Q So wouldn't you agree that an inaccurate understanding of the process is a training problem?

A So the -- the cause codes in the descriptions, those come from a NERC cause code library. Those are not written by us. They are used across the industry.

So this does not speak to a training issue. This is when he set the speed to 3602, and he was seeing the frequency okay light, he did not make further adjustments. So his training and experience, he knows that he needs to be slightly faster than the system, and being at 3602, his indications tell him that frequency is okay, so he made no further adjustments.

Q Okay. If you could read the italicized portion under the next contributing cause.

A Sure.

Contributing cause Alpha 3 Bravo 3 Charlie 06, individual underestimated the problem by using past events as basis. The parenthetical portion states: Based on stored knowledge every past events, the individual underestimated problems with the existing event and planned for fewer contingencies that would be needed.

Q So you stated that this terminology does not come from Duke Energy Florida, correct?

A Correct.

Q But your RCA team still found that this was applicable to this situation?

A It was a contributing cause.

Q Yes. So as a contributing cause, isn't knowledge of contingencies something that should be a matter of training as well?

A I am sorry, you were moving away from the microphone, I couldn't hear you.

Q Isn't the knowledge of the contingencies that should be in place a matter of training as well?

A Sure, to an extent.

Q Okay. And then the next contributing cause, the italicized portion, if you would read that?

A Sure.

Contributing cause Alpha 6 Bravo 2 Charlie 01, practice or hands-on experience less than adequate. The parenthetical portion states: The on-the-job training did not provide opportunities to learn skills necessary to perform the job. There was not enough practice or hands-on time allotted.

Q Thank you.

So this contributing cause reflects that the RCA team explicitly called that cause a lack of adequate training, right?

A This speaks to the operations team supervisor.

Q Not to the operator?

A No.

Q Okay. But training the operations team supervisor is also Duke's responsibility, correct?

A That's correct.

Q If you could read the italicized portion under the next contributing cause?

A Just the parenthetical portion?

Q Yes.

A Okay. So the contributing cause, Alpha 5 Bravo 1 Charlie 01, format deficiencies. The layout of the written communication made it difficult to follow. The steps of the procedure were not logically grouped.

Q And then one moment.

So isn't it true that Duke knocked this operator or the OTS that's responsible for creating the written communications?

A That's correct.

Q If we could go back to the previous contributing cause. On Bates page 56, there is a table, could you turn to that for me?

A Sure. Okay. That's page eight you are referring to of the RCA document?

Q Yes.

A Okay.

Q I am sorry, page nine.

A So Bates 56?

Q Yes. So in the second row, third column, starting with the term operations, could you read that box aloud?

A The consequence column?

Q Yes.

A Operator and operations team supervisor could not rely on the procedure for guidance during the event (contributed to).

Q I am sorry, the one right above that.

A Oh, okay. The on-the-job training barrier?

Q Yes.

A Okay. Operations team supervisor experience consisted of job shadowing for approximately three months. Shadowing only provides training on the conditions that existed during the shadowing.

Q Thank you.

Going back to page four of the RCA, the next contributing cause A5B2C08, would you read the parenthetical under that one?

A Sure.

Alpha 5 Bravo 2 Charlie 08, incomplete/ situation not covered. Details of the written communication were incomplete. Insufficient information was presented. The written communication did not address situations likely to occur during the completion of the procedure.

Q And would you also read the last sentence of that contributing cause?

A Sure.

The last sentence states: Enclosure 5 instructions are incomplete, stopping mid step.

Q And isn't it true that this operator was not responsible for the written procedure being incomplete?

A So the way that that enclosure works -- but to answer your question, the operator does not write the procedure, but the -- the procedure flow, the body of the procedure puts you into the enclosure, but it doesn't direct you back to the step that you were previously on.

So from a branching perspective in a

procedure, that was the portion that was stopping mid step. That's what that speaks to. The step says, go to the enclosure, but the enclosure doesn't say, resume the step you were just at prior to branching to the enclosure.

Q Okay.

CHAIRMAN CLARK: Ms. Pirrello, give me -- I would like to take about a five-minute recess. Let's give everybody a quick restroom break, and we will regather in about five to seven minutes.

MS. PIRRELLO: Thank you.

(Brief recess.)

CHAIRMAN CLARK: Ms. Pirrello, my apologies for interrupting you. You may continue, please.

MS. PIRRELLO: That's quite all right, Mr. Chairman. Thank you.

BY MS. PIRRELLO:

Q I only have a couple more of these contributing causes that I wanted to discuss.

A Could you remind me where we left off --

Q Yes.

A -- or where you are going to resume, please?

Q I will remind everyone. I believe we just finished the one titled Incomplete/situation not covered. So if you could read the current parenthetical

under A5B2C01.

A Okay. Alpha 5 Bravo 2 Charlie 01, limit inaccuracies?

Q Yes.

A The parenthetical states: Limits were not expressed clearly and concisely.

Q Is my understanding correct that this means that the limits were not expressed to this operator rather than that the limits were not expressed by this operator?

A They were not expressed by the operator, but this cause code, again, is -- comes out of a book of cause codes, so we don't write them. But the situation was that 3602 is a target, but adjustments to turbine speed may be necessary in order to achieve the auto synchronization.

Q But isn't it true that this operator was not aware or was mistaken about whether 3602 was a target or a set point?

A He treated it more like a set point. He didn't make any adjustments because his frequency okay light was illuminated. So when your indication that tells you that your frequency, which is the electrical view of a turbine speed, is indicating that you have good turbine speed or good electrical frequency, he made no further adjustments.

Q If you could go to Exhibit 64. It's the draft of the RCA.

A Sure.

Q Bates page 201.

A I have some help to be more efficient in navigating the documents now.

Q Great.

A Okay. And Bates page 201?

Q Yes.

A Okay.

Q So there are some comments sort of in the margin on this page. Is SJ you?

A I don't believe so. I am not sure who -- that might be the Microsoft Word decoder for someone's name, but I am not certain.

Q Okay. So typically these decoders use someone's initials, and there is no one else on the investigation team with the initials JS.

A Yeah, I was just looking at the other one and that's saying SJ 10, which would be the tenth comment, so it's probably me transposing JS to SJ.

Q Okay. So then MBJ is Barbara Jo Martinuzzi?

A Barbara Jean I believe, but yes.

Q Okay. So in -- there is sort of three grouped

comments there. Could you read that second grouping, your and then her comment?

A Sure.

Why would the amber permissive lights show unit was ready to sync if more adjustments were needed to allow it to sync in auto? What would trigger operator to make adjustments if all lights indicated he was good to sync? This contributing cause doesn't make sense to me.

And then the response was: When you exceed 3600 all three lights will flicker and illuminate each time when the synchroscope reaches 12 o'clock, however it will not sync if the frequency and voltage angle are not aligned. The only way to do this is to increase speed.

Q So Ms. Martinuzzi was explaining that even though the lights will light up, that doesn't mean it's actually in the correct frequency and voltage to sync?

A The context of this may have been to help develop the interview questions of the operator. So this -- this timing I don't recall, going on eight months ago, if we were still developing questions for operator interviews on that part. But the -- let me just reread that real quick.

Okay. Yeah. The comments that are there were maybe in preparation for interviews, or I don't remember the exact context of those.

Q But it is your expert's assertion that the lights may flicker, but that doesn't mean that the unit is in the correct position to sync?

A So Barbara was -- is not -- was not the expert for this. She's the facilitator of the process. She is the OE specialist that ensures we follow the corrective action program, not a -- not a technical expert in that discussion.

Q Okay.

A So the statement, though, barring something else preventing breaker closure, when you have all three lights illuminated and there is though other permissives that are holding you out from successive breaker closure, you would expect breaker closure at the 12 o'clock position.

Q Okay. Turning back to the final RCA --

A Sure.

Q -- the last contributing cause, if you would read that parenthetical?

A Alpha 4 Bravo 5 Charlie 9?

Q Yes.

A Change related documents not developed or revised.

Q And the parenthetical under that one?
A Sure.
Changes to processes resulted in the need for new forms or written communications, which -- I can't make out the last sentence. It's kind of double printed.
Q My reading is were not created but --
A Seems reasonable. It's hard to read with the header of the PDF document.
Q Agreed.
So again, isn't it Duke's responsibility to create those written communications?
A Sure. There is something that is important in that statement, though, where it states changes to processes. And as discussed in the Fifth Set of Interrogatories, 8 through 14 --
Q Uh-huh.
A -- we discussed that the laminated -- the laminated document was affixed to Unit 5 because that unit changed from a two breaker facility to a single breaker facility. So that's why it got an operator aid to help them with that change.
Unit 4, during the breaker upgrades, did not change the topology of the substation or the way that the unit comes on-line. So Unit 4 has always had

breaker 3233 and 3234. Then Unit 5 used to have breaker 1660 and 1661. Now it only has one single breaker, and that was the change.

So there was no change to Unit 4, which is why there was not a change document provided. It's an enhancement because, earlier, as you discussed, you look at one sync panel and you see a laminated aid, and maybe it was the gentleman mentioned that, that that was the aids for Unit 5, which changed. So that was there to help assist the operators understanding the change to their normal synchronization process.

Unit 4, since, since 1982, has had the same breaker layout, the same closure process, everything else like that. So there would have been nothing to train them -- there was no change to train them on.

Q Okay. So in the narrative of your testimony you state that the failure was not of training, but we just walked through these seven contributing causes, all of which were related to training problems or communication problems within the company?

A That's not my characterization. They are contributing causes, which we acknowledge, but they are contributing because whether they occurred or not, the outcome of the event would have been the same. Had we had the world's best operator that had been trained that

morning on synchronization, that failed device would
have led to the same result.
Q Could you go to page seven of your testimony?
A The direct testimony?
Q Yes.
A Okay. Okay.
Q Starting on line six, could you read the sentence starting with in fact?
A Sure.
In fact, had the operator closed the breaker one second later, no damage would have occurred and the failure of the relay would have gone unnoticed until the next scheduled interval or potentially the next attempt at manual synchronization.
Q So isn't that statement in your testimony contradictory to what you just said, that even if the operator had done this correctly, that the failed relay still would have led to the same result?
A The statement I made was if he closed it at that one second early time. This is written under the supposition that he is closing it at the correct time. So it's two different scenarios, right? If -- if he closed it at the correct time and the device was failed, we never would have known. Had he closed prematurely and the device been good, this event wouldn't have

happened. So when he closed early, the protective device failed to do its job, and that's what led to the event.

Q Okay. Let's go back to page two of the final RCA.

A Okay. Page two of the RCA?

Q Of the RCA. It's Bates 49.

A Okay. Thank you.

Q So there is a narrative description of the events that occurred on this day, and we already discussed that one of the initial issues was with the boiler feed water pump, correct?

A That was early in the night.

Q Yes. So isn't it true that the RCA team determined in these drafts that we've been looking at, which are Exhibit 64, that the operator should have stopped when this initial problem with the boiler feed water pump occurred and they should have consulted the generator trip EOP?

A So the seven o'clock trip, he would have entered the emergency operating procedure for boiler trip, which is a referenced document. It's a checklist post event.

So that entry into the emergency operating procedure would have ceased after the boiler was reset and the unit was placed into startup. So you would have put the EOP to the side. You are done using that procedure. Then you would pick up the startup procedure. And that was at roughly 10 o'clock when they entered the start up procedure.

Q But on Bates page 159 in CEL 64.

A I am sorry, could you repeat?

Q Bates 159.

A Okay.

Q Exhibit 64.

A And the Bates page, I am sorry, one more time?

Q 159.

A Okay.

Q And just while we are here, this Exhibit 64 is various drafts of your root cause analysis, correct?

A That's correct, with drafts by different team members and reviewers.

Q Okay. So on this page, 159, under the last contributing cause on that page, it says: Operations should have stopped when Unit 4 initially tripped on low drum level and consulted the generator trip EOP 1.

Skipping down, it says: Through interviews, it was noted that trips caused by the main boiler feed water pump were not uncommon and that EOP was typically not consulted for this type of event.

So -- and then someone made a comment there saying that protocol states that we respond to unit emergencies and then refer to a procedure?

A Right.

Q So isn't it correct that they did not refer to the EOP for the boiler feed water pump trip?

A So the statement there that they did not refer to it, that's what it states. Again, there is a large time gap that I want to make sure is distinct.

So the EOP for the feed water pump trip was early in the evening. Again, you have exited that procedure whether you picked it up or not, you are no longer looking at it. So the use of the EOP had no bearing on the out-of-phase synchronization portion of this only.

So that being said, the trip three hours early, you have exited the EOP entry conditions, and as stated by operations protocol, you take prompt action to resolve plant issues. Then as you reset the plant, you bring it into the startup and you are into the startup procedure. So the EOP use is not associated with the startup of a plant and the synchronization of the unit, by time or procedure.

Q Understood. But isn't it correct that your team here has said that the synchronization should not

have been attempted after this event, the EOP should have been consulted, and that procedure was not followed?

A In one of the drafts there, that comment -- those comments exist.

Q Okay. And just to be clear, EOP is emergency operating procedures, right?

A That's correct.

Q So instead of consulting the emergency operating procedures or their supervisor, this operator, who we've already established had not been trained or shadowed in this particular situation, attempted to sync the generator to the grid; is that correct?

A No. The shadowing discussion was around a shift supervisor --

Q Okay.

A -- not -- not around the journeyman operator who was operating the plant.

So the journeyman operator had been through, in his career, multiple boiler feed water pump related trips and was -- was experienced in resetting the plant and going into the startup procedure.

Q And isn't it true that the line saying that the sync shouldn't have been attempted is omitted from the final root cause analysis?

A I am sorry, I couldn't hear you. One more time.

Q That line that we just discussed where someone said that the -- that -- I am sorry, I lost my thought -- the line saying that the sync shouldn't have been attempted was omitted from the final RCA, correct?

A That opinion, or that statement from that particular reviewer did not make it to the final approved document.

Q Okay. So if we could go back to Staff's Exhibit 54, your response to question 12A which appears on page three.

A Okay.

Q So the RCA says that between each failed synchronization attempt a walkdown was performed, right?

A Correct.

Q And your response to staff here says that the proper procedure for an operator to follow after a failed auto synchronization attempt is to, quote, perform a walkdown to inspect the various potential failure modes, in turn, if an issue is discovered, it's corrected, the system is reset and synchronization is a tempted again, unquote; is that right?

A That's what the document states.

Q Okay. Could you define walkdown and describe

for the Commissioners what that would entail, maybe the distances and the number of people involved?

A Sure.

So the relay room is adjacent, immediately adjacent to the main control room. There as side door from the control room that leads you to the relay room. So the walkdown discussed there, as also discussed in the root cause, you would walk by the relay panels, which are maybe 25 feet from the control board, you would look for indications, the lights were not as you expected. You would have a lockout relay which would be in the tripped position instead of the reset position. Those are permissives that prevent breaker closure and those have to be reset by either pressing a reset push button or manipulating the lockout relay back to its normal position.

Q Thank you.

So you have provided this demonstrative exhibit here that shows the dashboard of Unit 4, is that right?

A It's the Unit 4 synchronization panel.

Q Okay. And as you just stated, the lockout relays are not on this panel, is that correct?

A Correct.

Q And neither is breaker 3233?

A The breaker is not physically located there. The breaker control switch is located on there.

Q Is that what was tripped?

A No.

Q Okay. So on page three of the root cause analysis, there is a table showing the timeline of events from this evening, on December 17th?

A Yeah, hold on one second.

Q Uh-huh.

A Okay.

Q Is it accurate to say that the first number in these times is hours and then minutes, seconds point milliseconds?

A Yes, on a normal power plant run at a 24-hour clock, so those are the 24-hour version of the times?

Q Okay. So I am going to abbreviate these times a little bit, but could you confirm for me the numbers in this table, they are automatically generated by the machine, they are not input by the operator or anyone else at DEF?

A The -- I am going to call them the time stamps, the one that give the millisecond resolution, those are system generated, whether it's by the distributed control system or the protective relay device. So those are easily spotted by the very high level resolution. Obviously, we can't count to a .7340 milliseconds, so those are all system generated.

The 22:53 and the 19:10, those are the control room clock. If the operators look up, they have a control room clock that they mark breaker close, you know, those sort of milestone activities on a shift.

Q Okay. Thank you.

So I am going go to round up a little bit with the decimal seconds, but the table shows that the first sync attempt occurred at 22:00:12.6, or 12 seconds after 10:00 p.m., is that right?

A Yeah. If it helps, you can just say at 22:12 or at 22:16, it will make it a little easier.

Q Okay. So then the second attempt was initiated at 22:16?

A That's correct.

Q Which is just four seconds after the first attempt, right?

A Yes.

Q And then the third sync attempt was initiated at 22:20, another 3.2 seconds after the second attempt?

A Those are minutes just -- oh, you are talking about the third one. Okay.

Q Yes.

A So, yes. Let's see, that's DCS time. One of the things just of note, the -- the relays, they have a clock, and the distributed control system has a clock. So a man with two watches never knows the time, and they are not exactly perfect to the millisecond resolution always on that part.

But, yes, very short durations because to reset those is a few steps away in the relay room or at a different panel, and you have operators on the radio communicating walking these things down.

Q Okay. So it's not the same person who is standing at the control board who would go and perform the walkdown?

A No. Typically, the board operator, he is monitoring the plant. He has on the order of 40 DCS screens Monitoring the 15,000 components in the plant, and the synchronization panel is at his back in the control room. And if he needs something from what we would refer to as a building operator, the building operator is supporting the operation of the unit, and you hit him on the radio, and you say, hey, can you check out this lockout? Hey, can you check out this, and you have your eyes and ears in the field to help you in a control room, because you can't walk away from the board in the middle of a startup, and so you rely on your building operators to be your eyes and ears out in the field.

Q Okay. So you would agree that even based on these time stamps, it's unlikely that the operator could have paged his colleague in the control room, asked him to look at a certain thing, that person checked that relay and reset it, and then told the other person that that was done and that person initiated the second or third sequence in three to four seconds?

A So the condition can be corrected before the time stamp is updated. So if you turn a switch, the time stamp doesn't instantly update until you press a reset button on the control system that rechecks the status of those devices.

So it's hard to tell with the DCS time stamps, because these panels that are mentioned there, the 86 Alpha and Bravo, and then the 3 Alpha Golf and 3 Bravo Golf, they are steps away from each other. They are seconds away from each other.

So these are not unreasonable to be talking with someone on the radio and walking just a few steps and saying, yep, I am resetting, and then walking over and pressing a reset button. So that the time stamps, they seem quick, and I don't know the exact distance or number of paces or seconds between them, but it's not a big room and you are not far away.

Q But the time stamp is created at the time that the synchronization is commenced, correct?

A Time stamp -- state that again. I am sorry.

Q So the time stamp reflects the next time that the person who is standing at the control board turned the switch to try to sync, correct?

A Yeah. I don't know without going back what point on the control system that's referring to. If it's the position of the control switch or if it's the time that the previous device was reset. So I can't state with certainty that that's the next time the reset was attempted.

Q Okay. But in the chart, it does say next to each of these times second attempt and third attempt?

A Right. And the point of that is to demonstrate if an activity took place in between attempts.

So as the troubleshooting discussion talks about you find a problem, you reset it, you try it again, you reset it, you try it again. So the time stamps there, I don't know what point that was created on, off the top of my head, but the sequence of the condition being corrected before a successive attempt is the portion that that's looking at.

Q And your testimony is that these things were

corrected in, or in subsequently three seconds?

A That's what the root cause states.

Q Okay. If we could go back to Exhibit 64.

A Okay.

Q On Bates page 200, there is a comment from MBJ, which we already said was Barbara Martinuzzi, correct?

A Uh-huh.

Q And that comment states, quote, operators did not complete a thorough walkdown after each trip, unquote, right?

A That's -- that's what the comment states.

Q Okay. Could you read that entire comment aloud for me?

A Sure.

The comment begins with: Yes. The operators did not complete a thorough walkdown after each trip, therefore, each time they attempted to sync there was another item holding them out. This particular item was missed on the first attempt by the operators due to the change in the light sequence and the operators were not aware of this modification. The OTS discovered, and then the comment ceases at that point.

Q Okay. And the change in the light sequence that she's referring to is the changes that were made

during the 2017 to 19 upgrades, right?

A Correct.

Q And you stated that there was no necessity to have instructions at Unit 4 because there was no change?

A That's incorrect. The location where no changes were required was the synchronization panel for Unit 4. The items that are discussed there, the 3 Alpha Golf and Alpha Bravo, those are on the plant line relay panels. So they are in different rooms. Those are the ones that have a laminated zip-tied instruction sheet that's affixed to both the Unit 4 and Unit 5 plant line panels.

Q But there was not a laminated instruction sheet affixed to Unit 4 at the time of this event, correct?

A That's correct.

Q And this comment seems to reflect that that would have assisted the operators because they were not aware of these changes, correct?

A I disagree. This states that the change in light sequence, and if you look at the preceding comment by SJ6, the SJ6 comment by me, this discusses the 3 Alpha Golf and 3 Alpha Bravo relays. So that's the light sequence.

These are two different rooms, two different functions that are not related to each other. The permissive that comes from the 3 Alpha Golf and 3 Alpha Bravo, that is a permissive to synchronize the unit, but it is separate and unrelated to the synchronization panel laminate or synchronization process.

Q All right. So that third paragraph under extent of condition on that same page --

A Sure.

Q -- it says that the plant line lockout relay panels were modified during 2017 and completed during 2019. And am I correct to say that that is not that the comment is referring to?

A So the plant line, if you begin at the third paragraph, the plant line lockout, 3 Alpha Golf and 3 Alpha Bravo, and then you look at the red comment that's referring to the same relays, the plant line lockouts, and the lights associated with the plant line lockouts.

And then in the response from Barbara, it also states the change in light sequence is the plant line light sequence.

Q So both this paragraph and Barbara are referring to the plant line sequence?

A That's correct. The paragraph, as the first sentence in paragraph three indicates, it's the plant line lockouts. Not generator lockouts. Not synchronization. It's a separate entity.

Q And Barbara says, quote, this particular item was missed on the first attempt by the operators due to the change in light sequence and the operators not aware of the modification, correct?

A That's correct.

Q Okay. And the language in the third paragraph under extent of condition is not the same as the language in the corresponding third paragraph on page three of the final RCA, is it?

A If you will give me a moment, I can do a word-for-word comparison.

Q Sure.

A I am sorry, I am failing to see a difference between the two. Could you point to a sentence or a specific portion of that fourth paragraph?

Q The last sentence of the third paragraph is not in this draft, is that right?

A Oh, the third paragraph. I am sorry. I am sorry. I was looking at the fourth one.

Q That's okay.

A No wonder I didn't find a difference.

Okay. Sorry one more second while I compare the third paragraph.

Q No worries.

A Okay. The last sentence beginning with detailed information on relay trip schedules along with lockout relay reset procedure would have assisted operations during the multiple attempts to synchronize. That is present in the final version of the root cause, but it is absent in the draft version that you referenced.

Q All right. Thank you.

In and that paragraph also refers to several operators who were not aware of the changes and did not chinning the relay panels on initial walkdown, correct?

A Several operators were on shift, and they -- they didn't -- they did not notice the difference in the lights.

Q Okay. And on Bates page 200, Barbara, in her comment, is also referring to multiple operators, plural, who, due to the change in the light sequence, were unaware of the modification?

A That's correct. We are still on the plant line relay panel.

Q Okay. So it was not just a single operator who was mistaken about this?

A I -- I can't quantify. There is not that many operators on shift, but if we said several, it was more than one.

Q Okay. Would you please describe for the Commissioners the steps that occurred in advance of the operator processing the information with the failed attempt and then making a decision in communicating that to his colleague in the adjacent room with the relays to decide to make a second, third and fourth attempt to sync?

A Sure. And I will reference the discussion about what a proper operator response is. And I apologize if I get the exhibit numbers wrong, but it's question 12 under the response to Interrogatories 8 through 14. And my exhibit help abandoned me at the moment, so I apologize.

So the process that we describe under question 12 talks about following the failed synchronization attempt procedure would free operators to perform a walkdown, which is what's described in there. And then they find an issue -- if an issue is discovered, it's corrected, which is the reset steps that are discussed in that timeline. And then a reset attempt. Reset is performed, then a synchronization attempt is performed again. And then it's iterative until you resolve the problem and you successfully automatically synchronize.

Q So based on the time stamps that we discussed earlier, doesn't is seem difficult to have made a

deliberate fact-based decision in the time between the first and second and the second and third attempt?

A Yeah. The time stamps that are noted in the root cause are quick in the intervals that's there. So -- and I can't speak because I wasn't on shift, I wasn't present when this -- this event was occurring, as to how that conversation flow went.

But again, regardless of the time stamp, as they reset things, the breaker closure event with these attempts and the resets that were there, the time stamps don't change the outcome. So even if it had been five minutes between reset attempts with conversation, a failed device and the early operator action still led to the same result.

Q So if we could go to page two of the RCA.

A Sure.

Q The last sentence there says that the event, quote, caused enough grid instability on the 230 kV to trip Citrus Combined Cycle Power Block 1 station off-line, end quote, is that right?

A That's correct.

Q And the narrative portion of the RCA suggests that this occurred after the fourth attempt, when the turbine attempted to sync out of phase; is that correct?

A That's correct.

Q But the timeline in this table that we were looking at shows that Citrus was tripped three seconds before the fourth attempt, and you said that the calibrations of the times may not be exact, but could you clarify whether Citrus was tripped after the third or after the fourth attempt?

A It was after the fourth, which was the failed event. And I am trying to locate the time stamp of the breaker 3233 and 34, when it actually closed. But the Citrus trip was a result of the out-of-phase synchronization at Crystal River.

Q Okay. So those time stamps, then, are off by at least four seconds?

A Could you -- could you show me or tell me which time stamps you are looking at? Because the timeline on page three, it does not have a time stamp for the fourth attempt, but there is an 11-minute time difference between 22:00 and 20 seconds and the Citrus trip at 22:00 and 11 minutes. So that 11-minute period is when the fourth attempt occurred, and that was when Citrus tripped.

Q So I am seeing the fourth attempt listed right under the Citrus Combined Cycle trip at --

A Oh, okay, I see it.

So that time stamp -- again, Citrus has

different clocks. And when you are talking .02 seconds between facilities that are not on the same clock, it's inconsequential. And we know the cause of the trip at Citrus was a restrained differential misoperation of the generator protective relay.

Q So the time stamps there say 22:11:44.7 for the Citrus event, and then 22:11:47.7 for the fourth attempt. Is -- my calculation there is that that's three seconds not a fraction of a second.

A Right, you are correct. And going by -- and I don't know if we state this anywhere. If these are the time stamps of the devices, or we did not put everything on datum zero, you know, T0, and then everything goes from there. Oops, I got lucky on that one. Let me get smarter with the cap. So not everything is -- T0 is not equal at Crystal River site and Citrus site.

Q But these time stamps aren't referring to T0, they are referring to actual 24-hour clock, as you stated before, correct?

A They are from the device that they were retrieved from. So if it's a protective relay that physically resides at Crystal River, and you asked at what time something happened, it tells you something. And then if you go to Citrus, and you ask a completely different device what time something happened, it -- so if the times are not synchronized by GPS clocks, which they are not in this case, it could have been three days apart, but chronologically, they happened within that same exact sequence.

So time is set and it drifts unless it's locked by a clock. So I could set a clock on a relay to any date that I wanted if I chose to, but when you look at the disturbance monitoring equipment or the digital fault recorders, that looks up the whole system. So you can see the sequence of events from Crystal River leading to Citrus.

Q   But as I stated, these times are, you know, 10:00 p.m., 22 hours, they are not reflective of time from, you know, first attempt or anything like that?

A   That's correct. They are device times.

Q   Okay. So -- so subject to check, would you agree that Citrus Power Block 1 has a winter generating capacity of 931 megawatts?

A   Approximately.

Q   Something like that?

A   Yeah.

Q   So would you agree that it's unusual for there to be so much grid instability that a separate plant is tripped off-line?

A   So the instability did not trip the units at

Citrus. A relay misoperation tripped the unit at Citrus. So a relay at Citrus responded to the Crystal River event, and due to a settings error, it tripped Citrus. It was not grid instability. This was not an out-of-step or anything that would be characterized as grid instability.

Q Page two of your RCA, the last sentence says the event also caused enough grid instability to trip Citrus, so is that inaccurate?

A It's accurate. It led to great instability differential currents. Only one of the units at Citrus tripped. So that was a relay misoperation. So the relay responded to what it was presented with and it made its decision to trip the unit. So we can see fault current present on the line between Crystal River and Citrus, which the gentleman earlier stated they are approximately three miles apart, so the Citrus relay responded to that and tripped the unit.

Grid instability has lots of definitions, so I want to be clear that Citrus is the adjacent unit. It didn't send a system-wide transient, or a grid instability or an out-of-step event.

Q Okay. But regardless, that would be an unusual event?

A Correct.

Q Okay.

A The event as a whole is unusual for an out-of-phase synchronization.

Q Yes.

And you said earlier that the number of supervisor positions is five. Could we go to the Exhibit 64, Bates page 160?

A I am there.

Q All right. So one of the comments that someone added under the first contributing cause that's listed on this page mentions that there was a reduction in supervisor position from 11 to six, and you stated earlier that there are currently five supervisors, is that correct?

A I believe they staff five supervisors at the facility for this same plant and the water treatment facility -- I am sorry, clean air facility.

Q Okay.

A I don't have an org chart to validate that.

Q Understood.

The last thing, page four of the root cause analysis.

A Sure. Page four?

Q Yes.

A Okay.

Q Are you there?

A I am.

Q Okay. The description under contributing cause A3B3C06 references a 17-minute timeframe for the event, but the chart that we've been discussing on page three only details about 11-and-a-half minutes of activity between the first and the fourth attempts.

A Uh-huh.

Q Are there other actions that occurred in those undocumented five minutes that are considered part of this event?

A No. I think that's just a discrepancy on the timelines. And we are talking about different clocks, and some of it is conversations and it was about, you know, those sort of things that weren't system generated times.

Q Okay. One second, Mr. Simpson.

A Sure.

Q All right. That's all I have for you. Thank you for your time.

A Thank you.

CHAIRMAN CLARK: Thank you, Ms. Pirrello.

Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman. I will --

THE WITNESS: Mr. Commissioner, before we begin, could I request a very short bio break before we get into the next line of questioning?

CHAIRMAN CLARK: Absolutely. We will take five minutes.

(Brief recess.)

CHAIRMAN CLARK: Before we begin, let me take just the liberty, a second to kind of poll everybody. I want to see what our timeline looks like.

We have three days scheduled for this hearing, but it appears we may be close to the end. I want to get a, just a quick idea how long you think you have got for questioning just so I can plan the afternoon. If this is three hours, we are going to knock off at 5:00. If it's an hour-and-a-half, we are going to muddle through this thing and get through it today.

Mr. Moyle.

MR. MOYLE: 10 minutes, give or take.

CHAIRMAN CLARK: Okay.

MR. WRIGHT: I don't have any cross, Mr. Chairman. Thank you.

MS. BRUCE: Maybe 15 minutes.

CHAIRMAN CLARK: Okay. Is that everybody?

Staff, what do you think?

MS. BROWNLESS: Two questions.

CHAIRMAN CLARK: Oh, my goodness, this could roll. We could be out of here actually by 5:00 today.

MR. MOYLE: You don't have any redirect?

MR. BERNIER: That's going to depend, but it's getting shorter by the minute.

COMMISSIONER GRAHAM: Maybe squeeze in before 5:00.

CHAIRMAN CLARK: That's right. Your redirect is limited, right?

Okay, with that said, thank you very much for that. Mr. Moyle, you are up.

EXAMINATION

BY MR. MOYLE:

Q Good afternoon.

A Good afternoon.

Q A lot of the points that I was going to touch with you have been asked by Public Counsel, so I am just going to hit a few points with you.

A She stole your thunder.

Q The root cause analysis, you were a part of that team, correct?

A That's correct.

Q And you were -- went to the meetings and participated, so you are comfortable with the product that's before the Commission that's attached to your exhibit, correct?

A That's correct. I sponsored the exhibit.

Q Right. And the contributing causes, I know you read a lot of the phrases out of there, but a contributing cause can be a significant issue, you would agree with that, correct?

A It's characterized as a contributing cause, but there could be shades of contributing, I suppose.

Q Or there could be something else going on. You have heard of the phrase contributory negligence?

A I am not familiar with the term, no.

Q Okay. There were a couple of phrases in here that caught my eye I wanted to ask you about, like under -- this is the summary of contributing causes, and you talked about the number of synchronization attempts. It would seem that if you do the same thing a number of times repeatedly that, you know, there might be something not working there. Did you all talk about that and agree that, well, maybe this wasn't the best sequence to keep hitting the reset button or the synchronization button when it was not working?

A So it's more detailed than that. I fully agree that doing the same thing over and over and expecting a result is the definition of insanity, right? However, in between each attempt, there was a corrective measure, a line lockout was reset, things were changed. So it's not the same conditions during each successive attempt.

Q Yeah. But these things were done, like, in a two- or three-second time stamp?

A Yeah, the time stamp part I -- I would have to go back and review, because clearly counsel brought up some good questions around that as to what clock they were coming from. But as we talk about this period is, depending on which paragraph you look at, 11 or 17 minutes, so clearly those seconds difference are in that broader timeframe of that 11 to 17 minutes.

Q And when you all do have a problem with operations, I assume that part of your training is, well, you know, you use your best judgment but we have other people that you can consult with, such as an operations superintendent or a station manager, is that right?

A That's correct.

Q Okay. And one of the comments in here is that that did not take place in this situation, correct?

A That's correct.

Q And you also make a comment that there was -- didn't appear to be a questioning attitude either, is that correct?

A Yes, that statement is it in there.

Q Okay. And that -- just tell me if I am right on that, but that's someone if you are operating, we used to have a rule, if you have to force it don't do it, and you kind of question and go, why is this not working? But that's something you try to instill in your people through training and other mechanisms, to say ask why this is not working rather than just trying the same thing over and over again, is that right?

A Yes.

Q But it didn't take place here?

A I disagree to an extent. They did not, as you stated, force something to happen. They reset components. They were taking measures to resolve the situation. So this wasn't a, you know, we are just going to keep on trucking until something happens --

Q Yeah --

A -- there were things that were changing during -- during that period.

Q Okay. I will -- but with respect to a questioning attitude, you found no evidence of that, correct?

A They could have improved their questioning attitude, and that's one of the corrective actions that's addressed by the root cause.

Q And when you do a corrective action, you do that because you want to say, hey, this was a problem that wasn't done. We are going to do it this way in the future, or we recommend it be done this way in the future, is that right?

A So corrective actions have different purposes. Some can be -- if it's an equipment failure, it can be a broke/fix. This valve broke, we fixed it. Some are procedure changes. There is different types of corrective actions, as you are aware. So there, each contributing cause is mapped to a corrective action that addresses that contributing cause.

Q Right. But if things -- if thing were done, done properly, or done a certain way, you wouldn't put a correction, corrective action item next to them, correct?

A There is nothing to correct, so there would not be a corrective action. Now, an enhancement is something that we would pursue, because, again, the spirit of the corrective action program is to identify and improve our processes.

Q All right. There is a statement in here that

says additional training resources are needed to fully train the shifts for the newly restructured organization. That was something that your group found, correct?

A That's correct.

Q And the newly restructured organization, what does that reference?

A So I don't know the exact date, but during the last several years, as Crystal River Coal has its capacity factor has decreased. Previously, the coalyard, which was a 24/7 facility, had its own control room at one corner of the site. The clean air operations was in another corner of the site, and the steam plant was in the plant's main control room.

So instead of having three remote organizations, and for a plant whose capacity factor went from near 100 to, I don't -- I don't know the exact number, but very low as a coal burning facility, they consolidated into one control room. So that way the coalyard, which no longer operated 24/7, doesn't need to have a shift supervisor 24/7. And then the control room supervisor, he monitors clean air as well as the steam plant operations.

Q But these changes, like the coal unit, how -- how -- that took place many years ago, did it not, you

shut down the first coal unit?

A   Crystal River 1 and 2 is unrelated, but the coalyard that's at the facility has always supported all four units, Crystal River 1, 2, 4 and 5. So Crystal River 4 and 5 continue to receive coal by barge or by rail. So that's what the material handling organization is responsible for.

Q   Let me ask it this way: The change that you just described, when did that occur? When did that organizational change occur?

A   Approximately 2018.

Q   And when did this situation occur?

A   December 2019.

Q   So it wasn't -- it was newly restructured, but it's been about a year, give or take, with respect to the timeframe, correct?

A   Correct.

Q   The page of your Exhibit JS-1, five of nine, there is a number of corrective action items in there?

A   Yes.

Q   What -- the assignee title, what -- what does that reference?

A   The assignee.

Q   Yeah, what does that reference?

A   That's -- the assignee is who is responsible for completing that task.

Q Okay. When it said this is something you found, I guess, to be a problem, that the evaluator shall obtain concurrence from assignee, or assignee, or supervisor, that was not done this in this case?

A I am sorry, could you give me a reference to --

Q Sure. This is your Exhibit 1, and it's -- my page is at 00052.

A Right.

Q Five of nine of your exhibit.

A Okay.

Q And so am I correct to believe, because it shows up in their corrective item, and based on your prior testimony that there was not concurrence obtained from a supervisor in this case?

A For which -- which action are you speaking to specifically?

Q See this corrective actions, the --

A Yeah, I understand which specific --

Q The first -- the first bullet there, describe specific actions taken or required.

A Oh, okay. Yeah. So that -- that is a description of did the corrective action.

Q Right. And then my question was, it didn't

take place. Your evaluator didn't obtain a concurrence from the supervisor, correct? That's why you put it in there as something to be done?

A Oh, no. No. That's incorrect.

Q Why?

A The assignee -- this is saying, and let's just, for example, say that the board or the Commissioners are your boss, I can't assign you a task to go do something without their concurrence. So that's stating that I can't assign you work without your supervisor's permission ahead of time.

Q Okay. So --

A So I can't say, Jon, you are going to go do this unless I get Mr. Clark to say it's okay.

Q I probably muddied that piece of the record. So let's just be clear that the operator on the event in question, he did not go seek the counsel of his supervisor when all of this was happening, correct?

A The supervisor was present with him. He was on shift.

Q Did they -- did they talk? Did he seek his counsel?

A There were discussions as a crew as to what they should reset and attempt to reset.

Q The -- underneath that, develop a generator

synchronation guide, synchronization guide operator for Unit 4, laminate and attach to the generator output breaker. Was that something that you found as something that should be done moving forward as a corrective action?

A Yes. That was an enhancement. As we discussed earlier, Unit 5 had one. And if you look at the big poster board, the lower right-hand corner, we mimicked the laminated guide that's on the Unit 5 sync panel. So now both Unit 4 and Unit 5 have the same general steps.

Q Is that picture in the record anywhere that you know of?

A Yes.

Q Okay. So -- so where is -- which one of the pieces of information is the synchronization guide on that picture?

A Sure.

Q Could you just, is it top right?

A It's the lower right. I will point at it. I promise I won't say anything so you will be able to hear me.

Q And you put it -- that picture right there was not how it was seen on the night of the event in question, correct?

A That's correct.

Q It didn't -- it didn't have that information in that laminated thing that was stuck to the --

A It did not have the operator aid that's shown on that picture. That is a result of the corrective action program.

Q And that's akin to a checklist. I heard you say checklist. I mean, that gives somebody something to follow moving forward when you have a problem, correct?

A It's not a checklist. They are not going to take a grease pencil. It's a -- by definition, it's an operator aid. It's a quick reference, instead of going through 110-page startup procedure to perform these specific steps, here are some reminders.

Q All right. An when was that put on there?

A It -- the due date showed complete, so it would have been an immediate corrective action performed within days after the event.

Q Yep. Okay. That's all I have. Thank you.

CHAIRMAN CLARK: Thank you, Mr. Moyle.

Mr. Brew.

MR. BREW: Thank you.

EXAMINATION

BY MR. BREW:

Q Good afternoon, Mr. Simpson.

Mr. Simpson, you have been through this a lot, but just to confirm, you are sponsoring the RCA --

A That's correct.

Q -- exhibit JS-1? And you stand by everything that's in it?

A Yes.

Q Okay. Was any analysis performed or provided to Duke management other than the RCA listed as Exhibit JS-1?

A I am sorry, I couldn't hear you real well.

Q Was any analysis or assessment of the event prepared for Duke management besides the RCA that shows up as JS-1?

A No our corrective action program, this is the deliverable of the event analysis and this is the document that follows the event.

Q So it's the one and only deliverable?

A Correct.

Q Okay.

A The one and only formal document.

Q All right. Now, the generator size is over 700 megawatts, right?

A It's 821 MVA machine.

Q MVA machine, so it's really big?

A A large, large generator.

Q Okay. Is it -- is it generally known by the operators that syncing that generator out of phase was bad for the system?

A Yes -- oh, bad for the system?

Q Bad for the generator.

A Bad for the generator, yes. I am not sure our plant operators have an in-depth knowledge of system transients and system operations resulting from an out-of-phase synchronization.

Q But they know it would be bad for the generator they are responsible for operating?

A That's correct.

Q Okay. And is it reasonably foreseeable that the generator was synced out of phase that damage might ensue?

A If the generator was synchronized out of phase, damage is likely.

Q Okay. Now, on your testimony at page three --

A Is that the direct testimony?

Q The direct testimony. Yes, sir.

A Okay. I apologize for my lack of knowledge on these legal documents.

Okay. I am there.

Q And beginning at line 13, you talk about matching the generator and the power system's electrical

parameters during synchronization. And do you see the sentence that begins at line 17, closely matching these parameters ensure torques are minimized if the power system begins to govern the prime mover's rotating field, do you see that?

A Yes.

Q Now, we talked earlier about the principal damage to the generator was the rotors, right?

A That's correct.

Q And they were --

A Single rotor.

Q Pardon?

A Single rotor.

Q It's a single rotor?

A Yes.

Q And that's the rotating element within the generator that moves the prime mover?

A It's the -- yes. So this -- for -- this is important for this particular machine type. This is an alter X type excitation system, which has a small generator affixed to the main generator field. So we make reference to the main field versus the exciter field, they are two different components.

Q Okay.

A So the main field is what was damaged during this event.

Q All right. So where the goal as stated in the sentence on line 17 is to minimize the torques for the power system by attempting to sync the generator out of phase, whether intentional or not, wasn't the exact opposite affect achieved, which was to instantly impose excessive torque on the generator?

A So the first half of that statement, the attempt was not to synchronize the unit. So upon the out-of-phase synchronization, the result would have been excessive torque and machine damage.

Q Okay. And the machine damage would be excessive stresses imposed on the components?

A Magnetic fields would cause heating of the rotor at the end bells, which is what we observed.

Q So you could have thermal damage, you could have torsional stress damage?

A Yeah, mechanical as well as electrical thermal damage.

Q Vibration damage?

A This case we did not have vibration, but it is a possible consequence of an out-of-phase synchronization.

Q Okay. So the potential thermal damage and the torsional stress damage would be reasonable foreseeable

if you tried to sync out of phase?
A If someone attempted to sync out of phase, that is foreseeable.
Q Okay. Is this the first RCA team you ever participated in?
A No, sir.
Q I am sorry?
A No, sir.
Q Okay. If we could go -- if you could go to the RCA itself --
A Uh-huh.
Q -- to the table I think on page three that you discussed before.
A Okay.
Q Okay. So just to confirm that you had -- the events were you had three failed attempts to auto sync?
A Correct.
Q Followed by red flag closing of a relay, which is the operator forced the closing of the breaker?
A He was not forcing a relay to close. He red-flagged a control switch.
Q Okay. So he turned a control switch to close the breaker --
A He -- he turned the control switch to reset the synchronization process. His intent wasn't to turn

the control switch to close the breaker.

Q What exactly did the red flag of the breaker do?

A That completed the circuit to the breaker closed coil on breaker 3233.

Q All right. And so he completed the circuit manually?

A That's correct.

Q Okay. And that's what led to the sync -- the syncing out of phase?

A The operator action of red-flagging plus the failed sync check relay led to the out of phase event.

Q Okay. Let's take them one at a time.

A Sure.

Q He initiated the action to close the switch?

A That's correct.

Q Okay. But for that action, there wouldn't have been damage to the generator?

A That's not the scenario that occurred. So, yes, that led to the event, but there is a protective device that -- that is present in that circumstance.

Q Taking one at a time.

A Okay.

Q He initiated the event by closing the switch. He may have assumed that the protective layer would

operate, but let's take that as a separate thing.

A Okay.

Q Is red-flagging the relay consistent with established startup operating procedures?

A Red-flagging the control switch, which was a step that was performed, that -- that would be a normal manual sync process had he been going for a normal sync.

Q Abnormal, meaning it was not included in the standard operating procedure?

A He was -- so this -- the attempts were for automatic synchronization, and as he operated the switch in manual, that's what, as you said, led to the event.

Q Okay. So -- in the RCA on page four, under the summary of root cause, under AB2C04, the last sentence that says, proper operational procedure would be to green flag the breaker placing the unit in a safe condition prior to repositioning the synchronization switch handle; is that statement accurate?

A Yes.

Q Okay. And so he, rather than green flag the breaker, he red-flagged it?

A That's correct.

Q Okay. What authority does a journeyman operator have to deviate from established procedures?

A With supervisor concurrence, or supervisor discussion, they have a procedure deviation process in those discussions with the supervisor.

Q Was that invoked here?

A I don't believe so.

Q Okay. You weren't present?

A I was not present.

Q You were not on shift?

A I was not on shift. I am not an operator. I am the shift worker.

Q You are not an operator, so you have never been on shift as an operator?

A That's incorrect. As talked about in my background, I spent years in nuclear operations.

Q You spent years as the design engineer in nuclear operations, were you an operator?

A That's incorrect. In the operations department, I was an operator. Now, I was management, not a journeyman operator.

Q Were you ever responsible for doing a startup of a generator?

A I have been start -- I have started up many units in both an engineering capacity as well as in my operations phase.

Q And in an operations experience, have you been responsible for implementing startup operating

procedures?

A As a -- as a operation's supervisor, yes.

Q Okay. If we can look at the RCA on page three, the timeline summary that you went through with OPC's counsel.

As I understand the block of information under the heading Timeline, do you see that?

A Yes.

Q Okay. Do the notes accurately indicate what occur? In other words, at 22:00:12, you had the first attempt to auto sync, right?

A Yes.

Q Okay. And the parenthetical says, permissive 86A&B lockout tried, right?

A Correct.

Q And so the corrective action that was taken was to reset those lockouts, right?

A That's correct.

Q Okay. No other corrective action was taken?

A Not under that -- that row.

Q Not within four seconds, right?

A Correct.

Q Okay. Then you have a second attempt where a different set of lockout relays tripped, right?

A They were still tripped.

Q Okay. And they were reset again?
A It's a different device. Not reset again.
Q Reset?
A They were reset.
Q So the only corrective action was to reset the tripped relays?
A That's correct.
Q No other action as was taken?
A Correct.
Q Okay. And then when we get to the fourth attempt, which is when the breaker was red-flagged by the operator, right?
A Yes.
Q Okay. That's when the unit attempted to sync to the grid, and that basically was, like, going 80 miles an hour and trying to put your car in second gear, it wouldn't do it, right?
A It connected for approximately 1.75 seconds, and there was a -- a system fault occurred during that period.
Q Okay. So what happened was, it was immediately exposed the system instantaneously to excessive stressers which caused another related trip?
A Correct.
Q Okay. But it imposed enough excessive

stressers during that time to cause the damage that ensued?

A That's correct.

Q Okay. Including leading to local grid instability that led to the trip of the Citrus unit, right?

A With a relay misoperation as well.

Q Okay. Did Duke report that outage to NERC?

A The misoperation?

Q The grid instability on the 230 kV line.

A Yes. We have to report under PRC4 any relay misoperations. And those are captured under the GADS, Generation Acquisition Data System. I might be off on the acronym, but we report our PRC4 misoperations quarterly, and the GADS reports are done monthly, I believe.

Q So Duke reported it as a reliability event?

A That's correct.

Q Okay. You had made a comment earlier that I wanted to go over. Correct me if I am wrong, you had said that the same result would have occurred regardless of the level of training, even if the operator had gone through training that morning. Do I understand you correctly?

A That's correct.

Q That statement is only true if the operator still elected to red flag close the relay, right?

A I am sorry, I couldn't hear you.

Q That result -- that statement is only true if the operator, notwithstanding his training, still elected to red flag close the relay, right?

A Given the same conditions, the result would have been the same.

Q Okay. Thank you, that's all I have.

CHAIRMAN CLARK: Thank you, Mr. Brew. Anyone else? Any other questions from any of the parties?

Staff.

EXAMINATION

BY MS. BROWNLESS:

Q Did the operator follow DEF's written procedures for manual synchronization?

A He -- he followed it to the steps that he could, as we discussed, in the branching step that was incomplete. So he was not attempting to manually synchronize, so he would not have been following the steps to perform a manual synchronization.

Q Okay. And did he follow the exact steps for auto synchronization of the unit?

A Yes. On all attempts, he followed the procedural steps, however, the auto synchronization failed to close the breaker.

Q Okay. And I am looking at page four of nine on your Exhibit JS-1.

A Okay.

Q Okay. Here's what I am confused about.

A Sure.

Q I thought your testimony was that he had a procedure that he had developed which was neither manual synchronization nor auto synchronization, and -- and that was red-flagging the breaker; do I have that correct?

A There was no procedure developed for red-flagging the breaker. He was attempting to get back to auto, or to get back to a known condition.

Q Okay.

A And that was a troubleshooting step, not a written document that said red flag, or they were going through a troubleshooting process.

Q Okay. And so he didn't have a written procedure for that particular action, nor did he talk to his supervisor about whether that was inappropriate?

A There was no written procedure, but the operations supervisor was present in part of the troubleshooting activities.

Q Was the operating supervisor present for that

particular operating procedure?

A For the step where he went back? He was in the control room. I don't know if he was standing at the panel next to him, but he was providing oversight of the unit.

Q Okay. And my understanding is the reason he took that particular action was because he had done it in the past successfully, is that correct?

A So if you have failed -- and there is two ways to look at that. If you fail as an operator to get a good manual sync, you have done that before. And so when he is saying he has done that before, it's not alluding to, I am -- I am flipping switches without any process.

So operators who perform manual synchronizations such as him, they don't always get it the first time. It passes around. So as the synchroscope is circling, if you are late or early and you close that switch and nothing happens, then you just have a failed sync attempt.

Q So this was past -- based on his past experience --

A Correct.

Q -- and training?

A Correct.

Q But it was not part of a procedure that was written, or approved, or preapproved?

A Correct.

Q Thank you.

CHAIRMAN CLARK: All right. Commissioners? Commissioner Fay.

COMMISSIONER FAY: Thank you, Mr. Chairman.

And I just have one question. I think Commissioner Graham is getting some sweet revenge over here because this is some fun engineering discussion that we are having.

You got a lot of questions about the RCA, and I think Mr. Moyle asked you a question about the corrective action component. You mentioned that you provided a distinction related to an enhancement. Is that -- just so I understand what we have here in the RCA for this incident, the corrective actions are just that, right? They are something in response to an issue that occurred and not, by definition, an enhancement?

THE WITNESS: So the contributing causes are still addressed. So the contributing causes, they support the problem statement or the event statement. And if during the course of interviews, investigations, if an operator says, you know, it would have been nice if I had this there, we take that as an enhancement and we implement that based on feedback and the continuous improvement process.

COMMISSIONER FAY: Okay. So you consider them the same thing?

THE WITNESS: So the -- there is no separate -- and some of this ties back to the tool we use. We use this tool called Plantview, and it just calls it a corrective action. In the software tool it says corrective action. There is not a separate box, or a code, or a drop-down that distinguishes corrective action or enhancement. They are all just lumped under the corrective action program rather than identifying them corrective action or enhancement.

COMMISSIONER FAY: Okay. Yeah, and that answers my question. I mean, it's -- it takes me back to, like, tort law. Just because you do something in response when something went wrong doesn't necessarily describe the thing that went wrong, but I think -- I think you do have a distinction there, it just may not necessarily show up in the RCA as a written distinction.

Thank you. That's all I have, Chair.

CHAIRMAN CLARK: Any other Commissioners have questions?

I guess I have a couple of simple questions.

THE WITNESS: Sure.

CHAIRMAN CLARK: The question is: How many times in a year would an event like this typically occur?

THE WITNESS: An out-of-phase synchronization?

CHAIRMAN CLARK: Yes.

THE WITNESS: Across the country?

CHAIRMAN CLARK: No, in your own shop.

THE WITNESS: It's -- so in my 15 years, I have heard of one within legacy Duke Energy, so the annual occurrence rate would be 0.00 something.

CHAIRMAN CLARK: And if I understand, the synchronization is simply -- is that another way of saying phase balancing? You are balancing the phases in the production?

THE WITNESS: It's not phase balancing, which would more allude to ensuring that you have equal currents between the polyphase system. This is the matching of the electrical system of the generator to the grid. And, you know, in some ways it's slightly analogous to if you drive a manual transmission and you are letting the clutch out and sometimes you stall, sometimes you grind the gears.

So that connection of those two rotating mechanical systems coming together as one unified system is what the synchronization event is.

CHAIRMAN CLARK: My last question has to do with something I didn't quiet understand. When the relay failed and the attempted force of the reset, had the warning lights been -- were there warning lights that said that that breaker was not operational, the relay was bad, I mean?

THE WITNESS: There is not. So the device, as we talked about some of the NERC standards in the six-year requirement. So this is an unsupervised device. There is no beacon light on it that says I am broken when it has a problem. Additionally it's located remote from the control room, so the control room operator has no visibility on it that it -- that has failed.

And the other just kind of point of note, as we talked about Unit 4 tripped at seven o'clock in the evening. The previous day, when it came on-line was a successful auto synchronization. So, you know, things break when they break sometimes.

So the unit successfully synchronized the night before and then they trip because of a boiler feed pump event.

CHAIRMAN CLARK: Commissioners, any other questions?

Mr. Bernier, redirect?

MR. BERNIER: Just very briefly, Mr. Chairman. Thank you.

FURTHER EXAMINATION

BY MR. BERNIER:

Q There has been questions regarding the inspection and maintenance of the Beckwith relay. Is there a stated manufacturer's expected life of the Beckwith?

A There is no stated manufacturer life of the device.

Q So it is a -- you indicate that it is a very reliable component?

A Correct.

Q And it was designed specifically by Duke Energy, by Beckwith to perform this task?

A Yes, so post event analysis and discussions with Beckwith, this was developed with aerospace engineers and aerospace pedigree. Manufacturers recognize the criticality of this device, and it's not, you know, designed in someone's garage. I mean it's a high pedigree device with an exceedingly low failure rate. The manufacturer was unable to even provide any trends, as they indicate in their failure report.

Q Thank you.

There was some discussion regarding the, in the root cause and the contributing cause, the hands-on experience, LTA, how would you describe the operator's, this particular operator's experience?

A So this particular operator, years experience, as we talked about, is on the order of 15. He is also an operator that is frequently, we call it stepped up. So when there is special projects, he is selected because he is highly regarded. He has -- he is revered by his peers. He is a chief operator.

And also, whenever there are supervisors that are on vacation or out sick, he is stepped up to perform the oversight role of the unit. And as we also talked about briefly, when he went to, I don't recall if it was JEA or Seminole, but when he went to their other facility, he was a unit supervisor. So he has management experience, journeyman experience, and he is highly regarded by his peers and leadership.

Q Okay. Thank you.

And Ms. Brownless asked a couple of questions regarding written procedures to follow during the troubleshooting process, and you indicated there is really -- no written procedure, if I wrote that down.

Why would there not be a written procedure for such an event?

A So troubleshooting is a bit of an art. You have to say, all right, I have this problem, what are the things that could be causing this problem? And then you systematically eliminate them. So, you know, a very basic analogy: I went into my bedroom and the light didn't turn on. Okay, what could it be? Do I have a bad switch? Do I have a bad breaker? Do I have a bad bulb? You know, those are the things you systematically eliminate them until the problem is resolved.

Q Okay. Thank you.

MR. BERNIER: That's all I have, Mr. Chairman.

CHAIRMAN CLARK: All right. Thank you, Mr. Bernier.

MR. BERNIER: May Mr. Simpson be excused?

CHAIRMAN CLARK: Yes, I am sorry. Mr. Simpson, you are excuse.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN CLARK: All right. Ms. Brownless, procedurally we have completed the FPUC, FPL/Gulf and TECO items. Where do we stand on remaining items?

MS. BROWNLESS: Yes, sir.

You are correct with regard to FPUC, FPL/Gulf and TECO all the issues have been stipulated to and approved, and therefore there is no need for further action.

With regard to DEF, as we indicated before, 16 through 22, 23A, 23B and 27 through 36 have been stipulated to and approved, so no further action is needed with regard to those issues.

With regard to Issue 1D, which is spreading the 246.8 million true-up over two years, 2022 and 2023, if I understand correctly the decision that was made in Docket No. 20210158-EI earlier today, that rate mitigation plan has been approved, and so I believe the answer to this would be that we also approve it in this docket as well. And do we need a motion on that?

CHAIRMAN CLARK: We will just go ahead and take these one at a time.

I assume that all the parties are in agreement that every issue is resolved in these matters? All the parties agree?

MR. REHWINKEL: The ones she listed out, yes, except for 1C.

CHAIRMAN CLARK: Yes, that's correct. We are talking 1D right now.

MR. REHWINKEL: Yep.
CHAIRMAN CLARK: We took care of all the other ones, strictly 1D.
MR. REHWINKEL: 1D is ripe for your approval.
CHAIRMAN CLARK: 1D is ripe for a vote.
MR. WRIGHT: Mr. Chairman, resolved or subject to a Type 2 stipulation.
CHAIRMAN CLARK: Yes. Yes. Correct. Thank you.
All right, I will entertain a motion.
COMMISSIONER FAY: Mr. Chairman, I am just going to make sure Ms. Brownless thinks this is consistent with what we would do, but based on the mitigation plan approved today in 20210158, we would request approval of Issue 1D, which accepts that plan?
MS. BROWNLESS: Yes, sir.
COMMISSIONER FAY: Okay. Thank you.
CHAIRMAN CLARK: Do I have a second?
COMMISSIONER GRAHAM: Second.
CHAIRMAN CLARK: I have a second.
Any discussion?
On the motion, all in favor say aye.
(Chorus of ayes.)
CHAIRMAN CLARK: Opposed?

(No response.)

CHAIRMAN CLARK: The item is approved.

All right. The big question remains on 1C. We can make a determination real quick. Would you guys like to brief?

MR. REHWINKEL: Yes.

CHAIRMAN CLARK: All right. You made it easy on everybody today, didn't you? Thank you very much.

Mr. Bernier.

MR. BERNIER: Apologies. I think I need to move Exhibits 8 and 9 into the record.

MS. BROWNLESS: Yes.

CHAIRMAN CLARK: Great idea.

MR. BERNIER: Thank you.

CHAIRMAN CLARK: We will enter those into the record.

(Whereupon, Exhibit Nos. 8 & 9 were received into evidence.)

CHAIRMAN CLARK: All right. You want to give the briefing information, Ms. Brownless?

MS. BROWNLESS: Yes, sir.

Briefs are limited to 40 pages and are due on November 15th, 2021, for consideration at the December 7th, 2021, Agenda.

CHAIRMAN CLARK: All right. Any other comments? Anything else to come before the Commission?

Commissioners?

When will the transcript be ready? Within 10 business days the transcript will be ready.

Anything else?

Mr. Rehwinkel.

MR. REHWINKEL: Yeah, I guess 10 business days will put it pretty close to --

MS. BROWNLESS: No, I -- I think we would ask the Clerk's Office, and I apologize for not having done this before, that there be daily transcripts so that the parties would have adequate time to prepare their briefs.

CHAIRMAN CLARK: Fair enough?

COURT REPORTER: Tomorrow.

CHAIRMAN CLARK: Sounds great. We will get started on it.

MR. REHWINKEL: I want to thank Commissioner Graham for looking out.

CHAIRMAN CLARK: He has never asked that question before. I don't know what prompted that.

All right. Anything else to come before the Commission?

Thank you all. We stand adjourned.

(Proceedings concluded.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 2nd day of November, 2021.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024