DUKE ENERGY
FLORIDA

Dianne M. Triplett
DEPUTY GENERAL COUNSEL

June 9, 2025

VIA ELECTRONIC FILING

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Duke Energy Florida, LLC's Petition for Determination of Need for DeLand West – Dona Vista Transmission Line;* Docket No. 20250078-EI

Dear Mr. Teitzman:

Enclosed for filing is Duke Energy Florida, LLC's (DEF) Petition for Determination of Need for DeLand West – Dona Vista Transmission Line and Appendix A to the Petition. Also enclosed is the testimony and exhibits of DEF witness Dave Rahman, which support the Petition.

Appendix A to the Petition and Exhibits DR-4 and DR-6 to Mr. Rahman's testimony contain confidential information. This electronic filing includes only the redacted versions of those documents. Contemporaneous herewith, DEF will file via overnight-delivery a Request for Confidential Classification.

Thank you for your assistance in this matter. Please feel free to call me at (727) 820-4692 should you have any questions concerning this filing.

Sincerely,

/s/ Dianne M. Triplett

Dianne M. Triplett

DMT/clg
Enclosures

299 First Avenue North ▪ St. Petersburg, Florida 33701
Phone: 727.820.4692 ▪ Email: dianne.triplett@duke-energy.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Duke Energy Florida, LLC Petition for Determination of Need for Deland West – Dona Vista Transmission Line
_________________________________/

Docket No.: 20250078-EI

Dated: June 9, 2025

DUKE ENERGY FLORIDA, LLCS PETITION TO DETERMINE NEED FOR ELECTRICAL TRANSMISSION LINE

Duke Energy Florida., LLC ("DEF"), hereby petitions the Florida Public Service Commission ("Commission") to determine, pursuant to Section 403.537, Florida Statutes, and Rules 25-22.075 and 25-22.076, Florida Administrative Code, that there is a need for the proposed electrical transmission line described herein. In support of its Petition, DEF states:

1. The name and address of the affected agency are:

Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

2. DEF is an investor-owned electric utility that provides electric service to customers in its service area. DEF's full name and business address are:

Duke Energy Florida, LLC
299 First Avenue North
St. Petersburg, FL 33701

3. All pleadings, motions, notices, staff recommendations, orders, and other documents filed or served in this proceeding should be served upon the following individuals on behalf of DEF:

DIANNE M. TRIPLETT
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4. DEF proposes to construct and operate an approximately 26.5-mile 230kV electrical transmission line that would extend from DEF's DeLand West Substation in Volusia County to DEF's Dona Vista Substation in Lake County ("DeLand West-Dona Vista Project"). At the time of construction of the DeLand West-Dona Vista Project, DEF will also rebuild/upgrade the existing 69 kV transmission in Volusia and Lake Counties along the same route. The line has a planned in-service date of January 2030.

5. The DeLand West-Dona Vista Project is subject to the Transmission Line Siting Act ("TLSA"), Sections 403.52-403.5365, Florida Statutes.

6. Pursuant to the TLSA and Section 403.537, Florida Statutes, and Rules 25-22.075 and 25-22.076, Florida Administrative Code, the Commission has jurisdiction to determine the need for the DeLand West-Dona Vista Project, applying the standards set forth in Section 403.537(1)(c), Florida Statutes.

7. The information required to be supplied for the need determination pursuant to Rule 25-22.076, Florida Administrative Code, is set forth in the testimony and exhibits of Dave Rahman and Appendix A hereto and are incorporated herein by reference. Specifically, Appendix A to this Petition includes confidential load flow study results and files.

8. DEF is charged with serving both its existing customers and new customers located in its service territory as well as any wholesale transmission customers. Currently, DEF forecasts continued customer and load growth in the territory affected by the proposed DeLand West-Dona Vista Project for the foreseeable future.

9. The data and analyses contained in Mr. Rahman's testimony, his exhibits, and Appendix A to this Petition demonstrate the need for the DeLand West-Dona Vista Project in the proposed time frame as the most cost-effective alternative available, taking into account the demand for electricity, the need for electric system reliability and integrity, the need for abundant, low-cost electrical energy to assure the economic well-being of the citizens of this state, the starting and ending points of the line, and other relevant matters pursuant to Section 403.537(1)(b), Florida Statutes.

10. Pursuant to Rule 25-22.076(5), Florida Administrative Code, Appendix A and the pre-filed direct testimony and exhibits of DEF witness Dave Rahman submitted contemporaneously with this Petition describe in detail the major reasons for the DeLand West-Dona Vista Project. Specifically, the Project is needed in January 2030 to: (a) improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek and Piedmont substations; (b) increase north-to-south power transfer capabilities, providing an additional transmission path and redistributing the power flows in Volusia and North Orlando; (c) relieve potential overloads and low voltage conditions under contingency events; and (d)

reduce line loading on existing transmission circuits.

11. In order to enable DEF and the Commission to comply with the notice requirements of Section 403.537(1)(a), Florida Statutes and Rule 25-22.075, Florida Administrative Code, DEF previously filed a Notice of Intent to File Petition for Transmission Line Need Determination on May 9, 2025. The Commission has set the final hearing for this docket for July 22, 2025. DEF will publish the notice of that hearing in the appropriate newspapers in accordance with the statutory requirements and the requirements of Rule 25-22.075(4), Florida Administrative Code.

WHEREFORE, DEF respectfully requests that the Commission:

A. Hold a hearing on this Petition in accordance with Section 403.537, Florida Statutes, Chapter 120, Florida Statutes, and applicable rules of the Commission.

B. Determine that there is a need for the DeLand West-Dona Vista Project, with the starting point at DEF's existing DeLand West Substation in Volusia County, and the ending point at DEF's existing Dona Vista Substation in Lake County, and that the cost and reliability benefits of the DeLand West-Dona Vista Project would be enhanced by construction of the line in a combination of new and existing right of ways, subject to the final corridor determination under the Transmission Line Siting Act; and

C. Enter a final order determining such need for the DeLand West-Dona Vista Project.

Respectfully submitted,

/s/ Dianne M. Triplett
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Attorneys for Duke Energy Florida, LLC

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Electronic Mail to the following on the 9th day of June, 2025:

Adria Harper / Jennifer Augspurger Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 aharper@psc.state.fl.us jaugspur@psc.state.fl.us	

APPENDIX A TO THE PETITION IS CONFIDENTIAL IN ITS ENTIRETY AND SUBJECT TO A REQUEST FOR CONFIDENTIAL CLASSIFICATION, FILED CONTEMPORANEOUSLY WITH THIS PETITION PURSUANT TO RULE 25-22.006, F.A.C.

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION TO DETERMINE NEED FOR ELECTRICAL TRANSMISSION LINE

DOCKET NO. 20250078-EI

DIRECT TESTIMONY OF DAVE RAHMAN

JUNE 9, 2025

I. INTRODUCTION AND PURPOSE.

Q. Please state your name and business address.

A. My name is Dave Rahman. My current business address is 6565 38th Ave N, St Petersburg, FL 33710.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as Director, Power Grid Planning.

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

A. My responsibilities include the direct supervision of engineers in the development of long-range electric transmission expansion plans. Major responsibilities for my position include ensuring transmission plans and assessments are done in accordance with all applicable FERC, NERC, and Regional Planning Standards and requirements. I also oversee transmission service request studies performed in accordance with DEF's Open Access Transmission Tariff (OATT) as well as NERC compliance activities associated with the Transmission Planner functional role. I have held this position and performed these responsibilities since May of 2022.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida with a Bachelor of Science degree in Electrical Engineering in 2002. I've been a licensed Professional Engineer in the state of Florida since 2008 and I have been with the Company, and its predecessor companies, since 2002 in positions of increasing responsibility. Before my current role as Director of Power Grid Planning, I have held multiple leadership positions as well as engineering positions in Generation, Transmission and Distribution.

Q. Are you sponsoring any exhibits in this case?

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

- Exhibit DR-1: DEF Electric Facilities Map (DEF general map);
- Exhibit DR-2: DeLand West to Dona Vista Reliability Upgrade Project Map;
- Exhibit DR-3: Schedules 3.1.1 and 3.2.1 of DEF's Ten Year Site Plan, filed April 1, 2025;

- Exhibit DR-4: CONFIDENTIAL Load Flow Summary Table;
- Exhibit DR-5: DEF Transmission Planning Criteria;
- Exhibit DR-6: CONFIDENTIAL Alternative Projects Load Flow Summary Table;
- Exhibit DR-7: Indicative schedule of licensing, design, and construction; and
- Exhibit DR-8: Project Decision Matrix.

These exhibits are true and correct to the best of my knowledge. The confidential exhibits are subject to a Request for Confidential Classification, filed under separate cover.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and support DEF's request for a determination of need for the DeLand West to Dona Vista Project ("Project"). Specifically, my testimony presents the following information in support of the Project:

1) General overview of the DEF transmission system;
2) A general description of the Project including the design and operating voltage of the proposed transmission line, the starting and ending points of the line, the approximate cost of the Project, estimate of the time for full project development, and the projected in-service date;
3) The specific situations, conditions, contingencies, and factors which

demonstrate the need for the Project, including a discussion of DEF's transmission planning process, the reliability benefits of the Project, and the general time in which the Project will be needed;

4) A summary discussion of the major alternative transmission lines or transmission improvements which DEF examined and evaluated in arriving at the decision to pursue the Project;

5) A statement of the major reason or reasons for adding the Project; and

6) The adverse consequences to DEF's electric system and customers if the Project is delayed or denied.

Q. Please summarize your testimony.

A. DEF is proposing to build a new 230 kV transmission line extending from DEF's DeLand West Substation in Volusia County to DEF's Dona Vista Substation in Lake County. This transmission line would upgrade portions of DEF's existing 69 kV line between DeLand West and Dona Vista to address future reliability limitations, which have been previously identified in DEF's transmission planning process. The Project for which DEF seeks a determination of need in this proceeding is for the new 230 kV transmission line, but the scope of work associated with the Project will also include a rebuild of the existing 69 kV line. An analysis of transmission alternatives resulted in DEF's selection of the project as the most reliable and efficient means to: (a) improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek and

Piedmont substations; (b) increase east-to-west power transfer capabilities of the transmission network by providing a new 230 kV circuit between the Volusia and Lake County areas of DEF's territory south of DeLand (the "Project Service Area"); (c) relieve potential overloads and low voltage conditions under contingency events; and (d) reduce line loading on existing transmission circuits. This Project is the most effective solution, considering the demand for electricity, improving the reliability and integrity of the electric system, and meeting the need for abundant, low-cost electrical energy to ensure the economic well-being of the state's citizens.

Furthermore, the Project meets area load requirements by serving existing customers and allowing for future industrial, commercial, and residential load growth. The estimated construction cost for the Project, which includes the 69 kV work, is $165 million. The final cost of the Project is subject to the ultimate line routing, length, and conditions of certification required by the Transmission Line Siting Board.

DEF asserts that the estimated cost of the Project is reasonable, and the transmission line will assure the economic well-being of the citizens of the state by providing electric service to projected new load in the region and improving the region's electric reliability by minimizing the region's exposure to multiple contingency events, and the need to mitigate single contingency events with uneconomic redispatch and operational grid reconfiguration.

II. OVERVIEW OF DEF'S TRANSMISSION SYSTEM

Q. Please describe DEF's transmission system.

A. The Company's transmission system includes approximately 5,400 circuit miles of transmission lines, which includes 500 kV, 230 kV, 115 kV and 69 kV lines. The Transmission system has approximately 530 transmission substations and over 50,000 structures including towers, poles and other related equipment and material that support a peak load of approximately 13,000 MWs. These assets deliver electric service to more than 2 million retail customers located throughout a 20,000 square mile area in densely populated areas around Orlando, St. Petersburg, and Clearwater, as well as rural north Florida, and west central Florida.

DEF's transmission system is part of the Florida interconnected power grid that enables utilities to exchange power. Within Florida, the Company's system is extensively networked and interconnected with other investor-owned utilities, municipal electric utilities, and rural electric cooperatives.

Q. Please provide a brief description of the existing load and electric characteristics.

A. DEF's load characteristics consist primarily of residential and commercial load with limited industrial load. DEF's historic and forecasted peak demand are provided in Schedule 3.1.1 and 3.2.1 of DEF's Ten Year Site Plan, filed April 1, 2025, provided in Exhibit DR-3. An overview of DEF's existing electrical transmission network indicating the general location of major substations and transmission lines is shown in Exhibit DR-1.

Q. Does DEF expect load growth in the vicinity of the Project?

A. Yes. Based on DEF's analysis, load local to this Project is expected to grow by approximately 25% over the 10-year horizon.

III. DESCRIPTION OF THE PROJECT

Q. Please describe the proposed transmission line for which DEF is seeking a determination of need in this docket.

A. The Project will consist of a new 230 kV transmission line extending approximately 26.5 miles from DEF's DeLand West substation in Volusia County to DEF's Dona Vista substation in Lake County (subject to final certification under the Florida Transmission Line Siting Act or "TLSA"). At the time of construction, DEF will also rebuild/upgrade an existing 69 kV transmission line in Volusia and Lake Counties along the same route. To be clear, DEF's TLSA application only applies to the new 230 kV transmission line, but DEF plans to rebuild the existing 69 kV line at the same time with the new 230 kV transmission line. This 69 kV work is an ancillary benefit to the Project.

The Project will serve DEF's existing and future distribution substations in DEF's service territory and increase reliability of the transmission network with a new 230 kV line. This Project is the most effective and efficient means to: (a) improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek and Piedmont substations; (b) increase north-to-south power transfer capabilities of the transmission network by providing a new 230 kV circuit between the Volusia and Lake County areas of DEF's territory south of DeLand; (c) relieve potential overloads and low voltage conditions under contingency events; and (d) reduce line loading on existing transmission circuits.

Exhibit DR-2 is a map showing the Project corridor route, along with the existing electrical facilities in the area. The corridor route is conceptual and for illustrative purposes only. The ultimate route will be selected through the TLSA process.

Q. What is DEF's timetable for licensing, design, and construction of the Project?

A. Pending the final TLSA determination, we anticipate initiating Land Acquisition activities and conceptual design in mid-2026. Engineering and Land Acquisition efforts are currently planned to conclude by June 2027. However, Eminent Domain proceedings are expected in this Project, and they may extend approximately one year before construction can commence, tentatively scheduled for May 2028. Construction is expected to take approximately 20 months, with a targeted

Energization date of January 2030. For additional detail, see the indicative schedule of licensing, design, and construction in Exhibit DR-7.

Q. What is DEF's estimated construction cost of the Project?

A. The current estimated construction cost of the Project is $165 million. This estimated Project cost includes the cost of the 69 kV rebuild, which is approximately $13.8 million of the $165 million. If DEF were to rebuild the 69 kV line as a stand-alone project, the cost would be higher (although DEF has not prepared an estimate for such a stand-alone project). Since the new 230 kV transmission line is proposed to follow the existing 69 kV transmission line, DEF is achieving efficiencies by including the 69 kV rebuild into the overall new 230 kV Project. As stated above, since the final route has not been selected, pending determination of the TLSA process, the costs are subject to various factors including but not limited to the length and route of the line, land and easement acquisition costs, environmental impacts, right-of-way preparation costs, etc.

Q. What is the proposed in-service date for the Project?

A. The projected in-service date is January 1, 2030.

IV. DEF PLANNING PROCESS AND FACTORS WHICH INDICATE NEED FOR THE PROJECT

Q. How does DEF determine the need for new transmission lines?

A. Each calendar year, DEF's Transmission Planning group performs analyses for the long-term, ten-year transmission planning cycle. These analyses are performed from three distinct planning perspectives. First, Transmission Planning must demonstrate that the DEF system will be in compliance for the ten-year planning period with the mandatory and enforceable NERC Reliability Standards, particularly NERC Reliability Standard TPL-001 (see Exhibit DR-5 for additional detail). If the analysis shows that the DEF system deviates from these standards, the Company must initiate either an operational mitigation strategy or a new transmission capital project to bring the system back in compliance with the standards. Second, analysis is performed to demonstrate transmission system compliance with FRCC reliability standards. This analysis is similar to the analysis performed to ensure system compliance with the NERC Reliability Standards, the primary difference between the two analyses being that the FRCC treats the 69 kV system as if it is part of the Bulk Electric System (normally 100 kV and higher voltage facilities). Third, additional analysis is performed to address the interconnection of generation, transmission, and end-user facilities. This includes new residential and commercial loads that require capital expansion of DEF's existing transmission system. Proposed transmission capital investment projects resulting from these analyses must, per DEF's transmission planning process, be reviewed by other DEF departments and work groups affected by the proposals for feasibility and implementation. Projects are then added to the overall Transmission long term capital plan.

Q. Did DEF perform any studies to determine the need for the Project?

A. Yes, DEF conducted transmission assessment studies in 2024. See Section V below for additional details.

Q. Please describe the contingencies that support the need for reliability improvements and increased transfer capacity.

A. DEF transmission assessment studies identified the contingency events shown in CONFIDENTIAL Exhibit DR-4 as the most critical scenarios for the Project Service Area.

Q. Does the Project introduce any new contingency scenarios that present a risk to the transmission system?

A. No. The Project mitigates contingencies without introducing any new ones.

V. MAJOR REASONS AND NEED FOR THE PROJECT

Q. Please explain the need for the Project.

A. Studies performed in 2024 revealed a need for the Project. Specifically, by 2025 there are multiple system limitations that will require reliability improvements for

Lake, Volusia, Seminole, and Orange Counties. These issues are explained below:

- There is a need to provide an additional power source to the Dona Vista load center. Historically, this load center had been served by three sources of power—the Central Florida to Haines Creek 230 kV line, the Piedmont to Welch Road 230 kV line, and the Lake Co-generation plant ("Lake Cogen"). For the outage of one of these 230 kV lines followed by the outage of the other (defined as a Category P6 multiple contingency event in NERC Reliability Standard TPL-001), the Dona Vista load center historically could rely upon Lake Cogen to serve the area while restoration of the lines took place. With the retirement of Lake Cogen and its 110 MW of power several years ago, there has been a need to implement a third power source and thereby avoid voltage collapse to the Dona Vista load center for the occurrence of the P6 event. Following the retirement of Lake Cogen and in the ongoing absence of a third power source, the Lake County Under Voltage Load Shed ("UVLS") scheme was implemented to prevent cascading voltage collapse and line overloads in the Dona Vista load center should the P6 event occur.
- Increased load growth has made it such that generation is now too far from the load center. As such, north-to-south power flow in the area is limited under several contingency scenarios. An additional transmission path via the Project will increase these much-needed north-to-south power transfer capabilities. Adding this new source also redistributes the power flows in the Volusia and

North Orlando load areas to a more robust condition.

- DEF must maintain its voltage and thermal loading criteria, in the event of unplanned outages. These contingency outage scenarios present a formidable challenge in our transmission system, which as stated previously must be addressed not only for the sake of reliability and customer service but also to ensure compliance with regulatory standards. By addressing this issue with the Project, DEF will enhance the reliability of our transmission system and ensure adherence to both FERC 715 and NERC TPL-001 requirements, thereby maintaining the integrity and stability of the power grid.
- As part of the aforementioned reliability needs, there is a correlating need to improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek, Piedmont and DeLand West substations.

In addition to these stated needs from a transmission planning perspective, there is also a need for increased flexibility for operations and maintenance, as well as to accommodate switching activities for future construction in the local area.

Q. Please explain the benefits of the Project.

A. The construction of the Project provides the following benefits to the Project Service Area:

- Provides a more reliable delivery of power to DEF customers now and into the future while addressing future customer load growth.
- Substantially mitigates customer impacts during contingency events.

- Provides resilient transmission service to the area.
- Improves voltage support in the area to efficiently and effectively serve existing and future customers in DEF distribution substations along the route of the project.
- Increases north-to-south power transfer capabilities of the transmission network by providing an additional circuit between the east and west areas of DEF's territory between north of DeLand West and Dona Vista.
- Increased north-to-south transfer capability helps support customers in the populated areas of the north Orlando portion of the DEF service territory under several contingency situations that could occur during high customer demand periods and/or storm situations.
- Reduces line loading on existing transmission circuits.
- Meets the Project Service Area's long-term reliability requirements.

Q. Is the Project the best alternative to meet the identified need based on the criteria in the applicable transmission line need determination statute, Section 403.537, Florida Statutes?

A. Yes. For the reasons discussed in my testimony, the Project is the best alternative, considering the demand for electricity, enhancing electric system reliability and integrity, and addressing the need for abundant, low-cost electrical energy to assure the economic well-being of the citizens of this state.

VI. DISCUSSION OF TRANSMISSION ALTERNATIVES

Q. Did DEF consider transmission alternatives to the Project?

A. Yes, DEF considered transmission alternatives to the Project to meet the identified need.

Q. Please describe the transmission alternatives that were considered and explain the reasons why they were rejected.

A. DEF evaluated four transmission alternatives to the proposed Project. Exhibit DR-8 is a matrix reflecting the four alternatives and how they rank on various criteria. Below is a narrative explanation regarding why each of the alternatives is not as preferable as the selected option. DEF notes that alternatives 1, 2, and 4 do not include the 69 kV rebuild scope that the Project includes, so these alternatives do not include the collateral benefit of completing that work within another project. If any of those alternatives were selected, DEF would have to incur the cost to complete the 69 kV rebuild project in the future. As discussed above, this would add more than $13.8 million to the cost of alternative 1, 2, and 4 below. The estimates provided for these alternatives do not include this additional scope of work.

Alternative I: The Seneca Lakes to DeLand West Project consists of a new 230 kV transmission line extending from DEF's Seneca Lakes substation in Lake County to DEF's DeLand West substation in Volusia County. The estimated construction cost of this alternative is $161 million. This alternative was rejected for the following reasons: 1) It does not provide the needed reliability improvements for all customers served from the existing 69 kV circuit between Haines Creek, DeLand West, and Piedmont substations as Seneca Lakes is not a centrally located substation and additional new 69 kV lines with new impacts to customers would be necessary to achieve the same level of reliability as the proposed project; 2) It requires eight (8) miles of new linear impacts to the area, which does not already have transmission due to no co-location opportunities with existing lines.

Alternative II: The Sorrento to DeLand West Project consists of a new 230 kV transmission line extending from DEF's Sorrento substation in Lake County to FPL's DeLand West substation in DeSoto County. The estimated construction cost of this alternative is $171 million. This alternative was rejected for the following reasons: 1) It does not provide the needed reliability improvements for all customers served from the existing 69 kV circuit between Haines Creek, DeLand West substations and Piedmont substations as Sorrento is not a centrally located substation and additional new 69 kV lines with new impacts to customers would be necessary to achieve the same level of reliability as the Project; 2) It requires eight (8) miles of new linear impacts to the area, which does not already have transmission due to no co-location opportunities with existing lines.

Alternative III: The DeLand West to Dona Vista 170 kV Project consists of a new 170 kV transmission line extending from DEF's DeLand West substation in Volusia County to DEF's Dona Vista substation in Lake County. The estimated construction cost of this alternative is $159 million. This alternative was rejected for the following reasons: 1) It does not provide the needed reliability improvements for all customers served from the existing 69 kV circuit between Okeechobee and Whidden substations; 2) It would require an extra cost of at least two new 230/170 kV transformers and a spare transformer, significantly increasing construction costs; 3) DEF does not have any 170 kV lines on its system, so if this alternative were selected, DEF would incur additional costs to maintain a spare transformer that could only be used for this line; 4) It does not provide for nearly as much power transfer from north to south as does the Project. Additionally, it offers limited transmission network flexibility and does not significantly enhance reliability in the service area of the Project. This is due to its greater susceptibility to adverse impacts of numerous contingencies in the event of a single point of failure, such as a 230/170 kV transformer outage, as compared to the Project.

Alternative IV: The DeLand West/Silver Springs to Dona Vista Project consists of two new 230 kV transmission lines extending from DEF's Dona Vista substation in Lake County to loop into the existing DEF's DeLand West substation to Silver Springs in Lake County. This creates two new circuits, separately connecting Dona Vista with DeLand West and Silver Springs substations. The estimated construction cost of this alternative is $179 million. This alternative was rejected for the following reasons: 1) New linear impact to a community that does not already have existing transmission; 2) Approximately 6.5 miles along U.S. 19 is surrounded by Ocala National Forest, and any impacts to the forest would trigger additional environmental reviews; 3) Eight (8) miles of new impacts to the area due to no co-location opportunities with existing lines.

Q. Please provide an additional explanation why Alternative IV is more costly and challenging to construct, given that the lines for this alternative would be sited through a national forest.

A. There are several additional challenges associated with routing a new transmission line through that National Forest, even though there is an existing road, U.S. 19, that already goes through the forest. First, the County confirmed the ROW is very limited in the area, with many underground utilities and sidewalks. In addition, because DEF would need to obtain additional easements beyond the width of the existing U.S. 19 ROW for its transmission facilities, the proposed project would automatically trigger a full NEPA (National Environmental Policy Act) review process, likely requiring the preparation of an Environmental Impact Statement (EIS). The timeline for an Environmental Assessment under NEPA is typically 12 to 18 months, and the timeline for an EIS is typically 18 months to 30 months. NEPA reviews for projects involve extensive public input, consultation with federal agencies (e.g., U.S. Forest Service, U.S. Fish & Wildlife Service), and mitigation requirements. The uncertainties and potential legal challenges inherent in NEPA make this route infeasible from a regulatory risk and project execution standpoint.

National Forests are highly valued by the public for recreation, conservation, and aesthetic reasons. Routing infrastructure through such areas often triggers strong opposition from local communities, environmental groups, and recreation users. This opposition can manifest in public hearings, legal challenges, and political resistance, complicating approvals and threatening project viability.

Assuming DEF could obtain approval under NEPA, routing through a national forest also requires extensive coordination with the U.S. Forest Service and possibly other federal agencies, introducing complexity and potential conflicts with existing land use plans, recreation zones, wilderness designations, or conservation easements. Forest Service policies often prioritize preservation and recreation over infrastructure development, leading to potential denial or stringent mitigation requirements.

Constructing a transmission line through national forest terrain presents considerable technical and logistical challenges. Forested areas often lack access roads, require specialized equipment and helicopter construction methods, and may involve steep grades, rock outcroppings, and unstable soils. These factors drive up both cost and schedule risk. In addition, construction windows are often restricted to protect wildlife or comply with seasonal environmental constraints, further limiting feasibility. Once constructed, there may be additional challenges to maintaining, inspecting, and repairing the facilities. Specifically, access roads may be limited or subject to seasonal challenges due to weather or land management restrictions. Vegetation management is also more complex.

For all these reasons, DEF rejected Alternative IV.

Q. Did DEF perform load analyses to determine the impact of the alternative solutions?

A. Yes, a summary of those load flows is attached as CONFIDENTIAL Exhibit DR-6.

Q. Did DEF consider any generation alternatives to the Project?

A. DEF did not perform any specific analysis to determine the viability of a generation solution at the location of the old Lake Cogen plant. However, DEF can say that a generation solution is not feasible because: 1) The Lake Cogen site is too small to site a new generation solution of the size DEF would consider; 2) The existing gas infrastructure may not be available to fuel a new unit; 3) Given that the Lake Cogen facility has not been operated for such a long period, it is likely that DEF could not reuse much of the Lake Cogen facility; and 4) Given DEF's standard unit prices for new generation, it would likely be more expensive to construct a new facility as compared to the Project cost.

VII. ADVERSE CONSEQUENCES OF DELAY OR DENIAL OF THE PROJECT

Q. Would there be adverse consequences for DEF's customers if the Project is not timely approved?

A. Yes, to ensure compliance with NERC standards and adequately serve the current and anticipated industrial, commercial, and residential demand within the Project service area, it is imperative to establish sufficient transmission. Without this added transmission, the system's reliability and integrity would fall short of the levels maintained and adhered to for other DEF customers, who benefit from adherence to our voltage criteria. Additionally, this load center in Lake County remains susceptible to multiple dual line outage scenarios.

Q. Should the Commission approve the need for the Project?

A. Yes. For all the reasons described above, the Commission should determine that there is a need for the DeLand West to Dona Vista 230 kV transmission line to preserve electric system reliability and integrity in the area and to maintain low-cost electrical energy for the economic well-being of the residents of Florida.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit DR-1

DEF Electric Facilities Map (DEF general map)

ATTACHMENT I

DUKE ENERGY FLORIDA

ELECTRIC FACILITIES MAP

(GENERAL MAP)

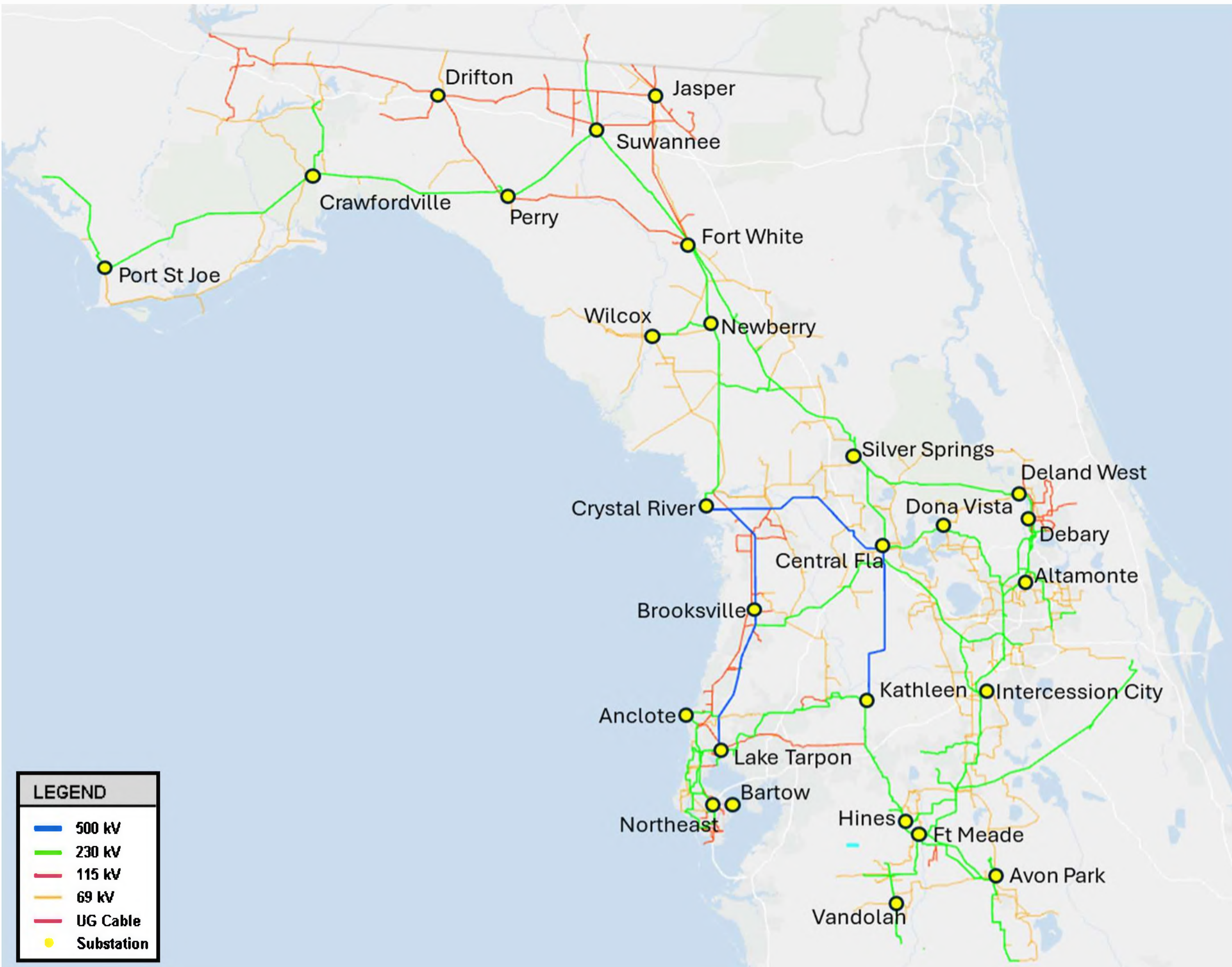
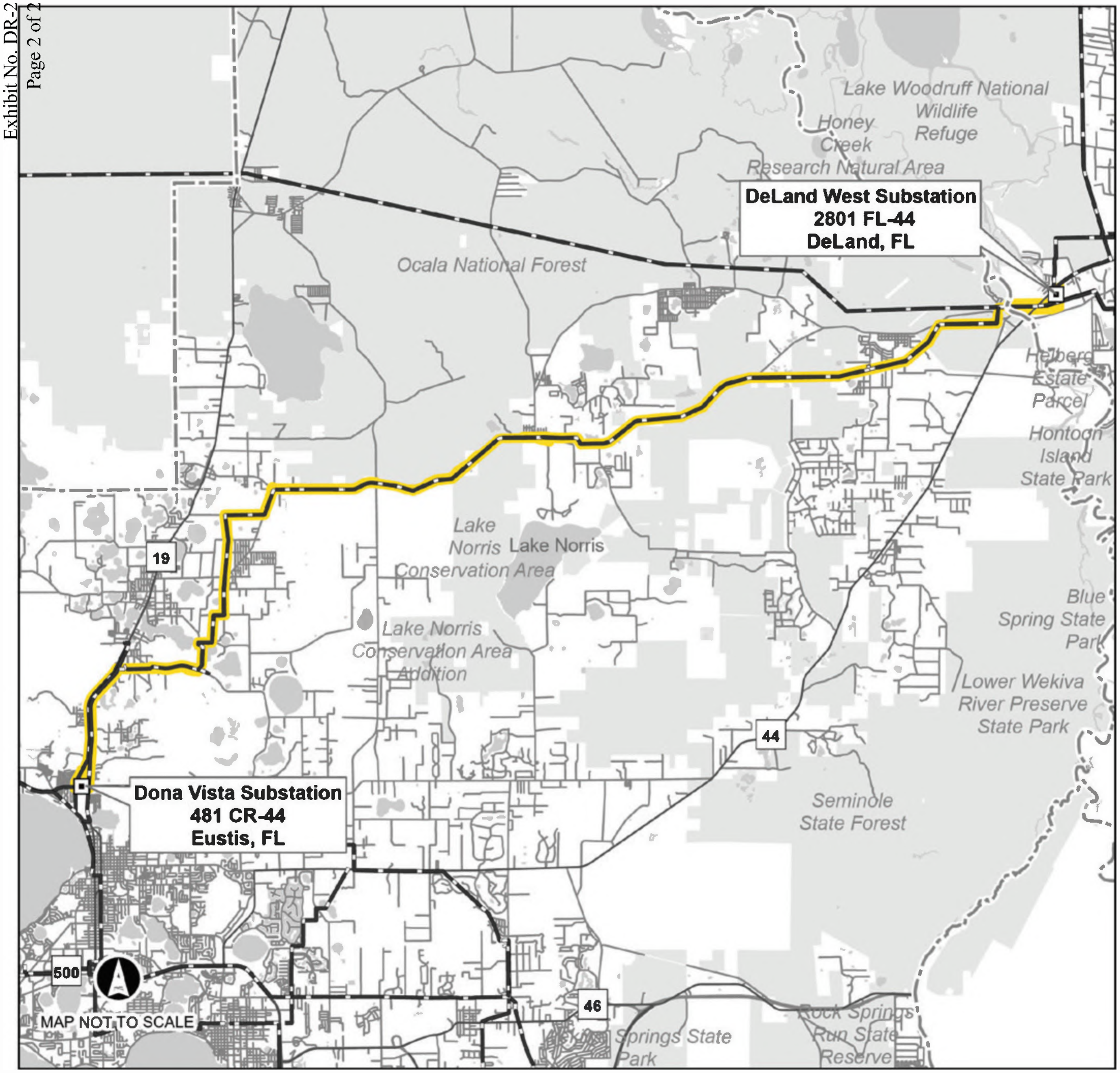


Exhibit DR-2

Deland West to Dona Vista Reliability Upgrade Project Map



DELAND WEST TO DONA VISTA RELIABILITY UPGRADE PROJECT

Legend

- Existing Substation Location
- Existing Duke Energy Transmission Line
- Transmission Line Corridor
- Lakes and Ponds
- Conservation Land
- County Boundary

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE®

Exhibit DR-3
Schedules 3.1.1 and 3.2.1 of DEF's Ten Year Site Plan, filed April 1, 2025

DUKE ENERGY FLORIDA

SCHEDULE 3.1.1

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)

BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2015	10,058	772	9,286	303	360	435	124	324	80	8,431
2016	10,530	893	9,637	235	366	466	100	339	80	8,946
2017	10,220	808	9,412	203	342	498	95	349	80	8,653
2018	10,271	812	9,459	257	386	532	83	387	80	8,545
2019	11,029	1021	10,008	230	394	566	86	414	80	9,260
2020	10,765	901	9,864	250	393	599	83	440	80	8,921
2021	10,835	1,010	9,825	375	394	623	85	451	80	8,826
2022	11,012	1,045	9,966	341	361	513	85	441	80	9,190
2023	11,357	827	10,530	476	352	550	88	459	80	9,352
2024	10,539	652	9,887	415	357	548	91	443	80	8,605
FORECAST:										
2025	10,810	351	10,459	415	380	581	94	468	80	8,792
2026	10,957	451	10,506	415	386	600	97	471	80	8,908
2027	11,052	451	10,601	415	392	618	101	475	80	8,971
2028	11,070	451	10,619	415	393	637	104	479	80	8,962
2029	11,145	451	10,694	415	394	656	107	484	80	9,009
2030	11,307	451	10,856	415	395	675	110	488	80	9,143
2031	11,392	451	10,941	415	396	694	113	492	80	9,202
2032	11,522	401	11,121	415	397	713	116	495	80	9,305
2033	11,633	401	11,232	415	398	732	119	498	80	9,390
2034	11,771	401	11,371	415	399	751	123	500	80	9,504

Historical Values (2015 - 2024):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) =Customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2025 - 2034):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DUKE ENERGY FLORIDA

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
HISTORY:										
2014/15	10,648	1035	9,613	273	658	815	109	236	237	8,319
2015/16	9,678	1275	8,403	207	675	845	131	240	170	7,409
2016/17	8,739	701	8,038	191	695	878	79	243	165	6,489
2017/18	11,559	1071	10,488	244	699	913	79	246	196	9,182
2018/19	8,527	572	7,955	239	711	948	82	251	164	6,132
2019/20	9,725	613	9,112	292	670	982	80	256	177	7,268
2020/21	9,654	679	8,975	319	671	1,006	82	260	175	7,141
2021/22	10,594	1,038	9,556	317	668	1,013	83	261	195	8,056
2022/23	10,474	1,047	9,426	317	638	975	83	262	194	8,005
2023/24	8,854	506	8,348	412	634	1,055	87	263	172	6,232
FORECAST:										
2024/25	11,795	952	10,843	412	642	1,080	90	269	197	9,105
2025/26	12,000	1,052	10,947	412	650	1,108	94	269	198	9,269
2026/27	12,099	1,052	11,047	412	658	1,136	97	270	199	9,328
2027/28	11,603	451	11,151	412	659	1,165	100	270	200	8,796
2028/29	11,695	451	11,244	412	660	1,196	103	270	201	8,853
2029/30	11,787	451	11,336	412	661	1,226	106	271	202	8,910
2030/31	11,787	401	11,387	412	662	1,255	109	271	202	8,876
2031/32	11,853	401	11,452	412	663	1,285	112	272	202	8,907
2032/33	11,934	401	11,533	412	664	1,314	116	272	203	8,954
2033/34	12,066	401	11,665	412	665	1,343	119	272	204	9,050

Historical Values (2015 - 2024):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent total cumulative capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Projected Values (2025 - 2034):

Cols. (2) - (4) = forecasted peak without load control, cumulative conservation, and customer-owned self-service cogeneration.

Cols. (5) - (9) = Represent cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Exhibit DR-4

Load Flow Summary Table

REDACTED

[redacted]

Exhibit DR-5

DEF Transmission Planning Criteria

DEF plans, designs, and operates its transmission system to comply with the North American Electric Reliability Corporation (NERC) Reliability Standards. The NERC Reliability Standard TPL-001-5.1 defines scenarios and expected levels of system performance that the Bulk Electric System (BES) should comply with in the long-term planning horizon. In general, the system will remain stable and both thermal and voltage limits will be within applicable facility ratings for each of the contingency categories listed on Table 1 of NERC Reliability Standard TPL-001-5.1 (Attachment 1 to this exhibit). DEF follows the standard guidance on system performance requirements for its transmission planning criteria. Category P0 addresses system performance with no contingencies and all facilities in service. Categories P1 and P2 address system performance following a single contingency. Categories P3 through P7 address system performance following multiple contingencies. Finally, the standard addresses system performance following Extreme Events where multiple facilities are removed from service. The need for transmission system upgrades is most frequently based on potential overload and/or under-voltage conditions associated with Category P2 through P7 type contingencies. For each of these types of contingencies, the response of the power system is analyzed to ensure system performance, resulting conditions, and severity of potential overload/undervoltage conditions are consistent with the NERC Reliability Standards. Generally, for Extreme Events, contingency analysis is used to identify potential situations of cascading interruptions and/or instability. There may be isolated cases where reliability concerns combined with other factors may justify a more conservative approach in developing alternatives than the normal planning criteria.

In addition to the NERC reliability standards, DEF also plans to the FRCC Regional Transmission Planning Process ("RTPP", document FRCC-MS-PL-018, Attachment 2 to this exhibit). The analyses performed as part of the RTPP are conducted under the same assumptions and requirements as that of TPL-001-5.1, the primary difference between the two being that the FRCC treats the 69 kV system as if it is part of the BES (normally 100 kV and higher voltage facilities).

In addition to the NERC and FRCC reliability standards, DEF develops projects to address other changes to the BES. These include changes of power transfers across areas associated with transmission service, generator interconnection requests, or generation retirements; improvement of overall reliability of the BES and non-BES (i.e., 69 kV transmission); and providing delivery point service as needed to wholesale or other large customers.

DEF also states its transmission planning criteria as part of its annual Federal Energy Regulatory Commission ("FERC") Form No. 715 Filing. Each transmitting utility that operates integrated transmission system facilities that are rated at or above 100 kV must annually submit this filing to the FERC. This filing includes regional power flow data, transmission system maps and diagrams used by DEF for transmission planning, a detailed description of DEF's transmission planning reliability criteria, a detailed description of DEF's transmission planning assessment practices (including, but not limited to, how reliability criteria are applied and the steps taken in performing transmission planning studies), and a detailed evaluation of DEF's anticipated system performance as measured against its stated reliability criteria using its stated assessment practices.

Attachment 1 to Exhibit DR-5

NERC Reliability Standard TPL-001-5.1, Table 1

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment 2 to Exhibit DR-5

FRCC Regional Transmission Planning Process

FRCC-MS-PL-018

FRCC
Florida Reliability Coordinating Council, Inc.

FRCC Document Classification: Public – This document may be shared freely with no access or use restrictions.

FRCC Regional Transmission Planning Process
FRCC-MS-PL-018
Effective Date: 9/1/2024
Version: 7

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TITLE	NAME	DATE
Version Author	Adrian Raducea	03/22/2024
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Document ID #: FRCC-MS-PL-018

This FRCC Regional Transmission Planning Process is based on the FERC approved Order 1000-compliant Open Access Transmission Tariffs ("OATT") of the Florida transmission providers, and includes Interregional Transmission Coordination Procedures also approved by FERC (see the July 30, 2015 and August 20, 2015 FERC Orders). Upon issuance of future FERC order(s) acting on or impacting the Florida transmission providers' OATT sections on their Transmission Planning Processes, the FRCC Planning Committee shall cause this Regional Transmission Planning Process to be amended and approved by the FRCC Board of Directors to incorporate the Florida transmission providers' FERC-approved OATTs.

Table of Contents   Page

1.0 Purpose

The objective of the FRCC Regional Transmission Planning Process ("Planning Process," "Regional Plan" or "RTPP") is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a reliable, cost effective and efficient transmission network in the FRCC Region.

The RTPP is intended to develop a reliable, cost effective and efficient regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent transmission planning environment.

The RTPP is intended to ensure the long-term reliability of the Bulk Electric System ("BES") in the FRCC region. However, nothing in this process is intended to limit or override rights or obligations of transmission providers, owners and/or transmission customers/users contained in any rate schedules, tariffs or binding regulatory orders issued by applicable federal, state or local agencies. In the event that a conflict arises between the RTPP and the rights and obligations included in those rate schedules, tariffs or regulatory orders, and the conflict cannot be mutually resolved among the appropriate transmission providers, owners, or customers/users, any affected party may seek a resolution from the appropriate regulatory agencies or judicial bodies having jurisdiction.

2.0 Terms and Definitions

2.1 Refer to North American Electric Reliability Corporation ("NERC") Glossary of Terms for definitions of capitalized terms not listed below.

2.2 Approved Cost Effective or Efficient Regional Transmission Solutions ("CEERTS") Project

A project that has achieved successful completion of the items in the Biennial Transmission Planning Process ("BTPP") steps 1 through 6, and approved by the FRCC Board of Directors for inclusion in the regional transmission plan. Any transmission projects that are being avoided due to the approved CEERTS project are removed from the regional transmission plan and associated regional models.

2.3 Enrolled Transmission Provider

Transmission provider that has been granted enrollment in the planning process for purposes of regional cost allocation by the FRCC.

2.4 Project Sponsor

The entity (or entities) that submit all of the required elements of a project proposal that is to be considered a potential CEERTS project.

2.5 Regional Plan

The "Regional Plan" also referred to as the "Regional FRCC Transmission Plan", is developed on an annual basis and consists of the Long-Range Study (including operational procedures) approved by the Board and the list of projects included in the Project Information Form ("PIF") as developed under the Annual Transmission Planning Process (ATPP).

3.0 Background

The RTPP is implemented in the FRCC as two distinct and separate processes: (1) the Annual Transmission Planning Process ("ATPP") and (2) the Biennial Transmission Planning Process ("BTPP").

The ATPP is the result of coordinating each of the FRCC members' local plans to develop the overall Regional Plan. The ATPP is closely tied to the region's NERC compliance activities, many of which have annual requirements for compliance with Reliability Standards for modeling (MOD), protection and control (PRC), facilities (FAC), and transmission planning (TPL).

The BTPP is initiated in odd-numbered years and runs concurrently with the ATPP in order to identify and evaluate more cost effective or efficient regional transmission solutions, or "CEERTS" projects. The BTPP includes a regional evaluation of the Board-approved plan to determine if there are solutions meeting CEERTS project criteria that could be proposed for regional cost allocation. The evaluation also considers potential transmission solutions to transmission needs driven by public policy requirements[1].

4.0 Applicability

4.1 FRCC Planning Coordinator/Authority

The ATPP portion of this RTPP is applicable to the FRCC as a Planning Coordinator/Authority. Note: The use of the terms "Planning Coordinator" and "Planning Authority" are interchangeable as it relates to this document.

4.2 Enrolled Transmission Providers

The cost allocation portion of the BTPP included in this RTPP is applicable to Enrolled Transmission Providers.

5.0 Responsibilities

5.1 FRCC Board of Directors ("FRCC Board" or "Board")

The FRCC Board shall have the responsibility to approve this document and ensure this process is fully implemented.

5.2 FRCC Planning Committee ("FRCC PC")

[1] To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency).

The FRCC PC is responsible for approving and endorsing the document for FRCC Board approval. The FRCC PC shall direct the Transmission Technical Subcommittee ("TTS"), the Stability Analysis Subcommittee ("SAS"), the Resource Subcommittee ("RS"), and the Regional Projects Subcommittee ("RPS") as appropriate, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the RTPP.

5.3 FRCC Regional Projects Subcommittee ("RPS")

As directed by the FRCC PC, the RPS shall be responsible for supporting the efforts associated with the BTPP or other duties as assigned by the FRCC PC. The RPS is also responsible for this document's review and modification before submitting the document for FRCC PC approval.

5.4 FRCC Transmission Technical Subcommittee ("TTS")

As directed by the FRCC PC, the TTS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

5.5 FRCC Stability Analysis Subcommittee ("SAS")

As directed by the FRCC PC, the SAS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

5.6 FRCC Resource Subcommittee ("RS")

As directed by the FRCC PC, the RS shall be responsible for supporting the efforts associated with the ATPP or other duties assigned by the FRCC PC.

6.0 Principles

It is the intent of the FRCC that the Planning Process be conducted in a coordinated, open, and transparent manner, including facilitation of information exchange, in such a way that it ensures fair treatment for all customers/users, owners and operators of the transmission system. This will be accomplished through the processes described herein.

6.1 Coordination

The FRCC expects its member transmission providers to consult and interact directly with their customers and stakeholders in providing transmission service and generator interconnection service, as well as with their neighboring transmission providers and FRCC Staff, on a regular basis. An open dialogue between transmission customers and their transmission providers takes place regarding customer needs. This interaction and dialogue between the customers and transmission providers are part of the transmission providers' local transmission network planning processes. Within those processes, topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. This dialogue is intended to provide timely and meaningful input and participation of customers during the early stages of development of the transmission plan.

The transmission providers communicate with their neighboring transmission providers on a regular basis, and the transmission providers facilitate communication and consultation between customers and their neighboring transmission owners/providers, specifically, if during the transmission service study process, a neighboring system's facilities are identified as being affected. This coordination process continues in a seamless manner at the local as well as the regional level with FRCC Staff, leading to each transmission provider providing an initial transmission plan which, when consolidated, becomes the initial FRCC regional transmission plan.

The initial transmission plans submitted to the FRCC by the transmission providers, which results from their local transmission network planning processes will be posted by the FRCC in accordance with Step 1 of the FRCC ATPP in Section 7.1 below. The initial transmission plan is reviewed by the FRCC Staff as well as all interested transmission customers and stakeholders.

The FRCC Committee process is used to finalize the initial transmission plan as submitted to the FRCC. In addition to transmission customers and stakeholders being provided timely and meaningful input and participation during the planning process with the transmission providers, the transmission customers and stakeholders are also given an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed by any transmission providers' initial transmission plan submittal in accordance with Step 2 of the FRCC ATPP.

This FRCC review process normally commences shortly after the submittal of the Ten-Year Site Plans ("TYSP") to the Florida Public Service Commission ("FPSC") on April 1st of each year. Once issues raised by interested stakeholders are addressed, including consideration of proposed CEERTS projects as set forth in section 7.2 below, the FRCC PC approves the proposed regional transmission plan and presents it to the FRCC Board for approval. Upon approval by the Board, which is expected in February of each year, the FRCC sends notice to the FPSC that the final regional transmission plan documents are available for their use and review upon request. Unresolved issues may be resolved under the FRCC Dispute Resolution Procedures.

6.1.1 Coordination of Transmission Service Requests

In order to coordinate transmission service requests within the FRCC, transmission providers will provide their long-term firm transmission service requests and generator interconnection service requests, in queue order, to the FRCC in a common format. The FRCC will consolidate all individual queues for coordination purposes and will post the consolidated queue for coordination purposes for all FRCC members to view.

6.1.2 Regional Reliability Evaluation Process

Through the *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests (FRCC-MS-PL-054)*, the FRCC Staff facilitates and coordinates the identification of potential third-party impacts within the FRCC region and evaluates transmission service requests to ensure that the transmission system within the FRCC region remains reliable, adequate and secure.

6.2 Openness

The openness principle is incorporated in this *FRCC Regional Transmission Planning Process* in which member transmission providers participate, along with other parties, in the committee and working processes at the FRCC as described below. The participants in the planning process at the FRCC are the sector representative of the FRCC PC. A list of representatives may be found on the FRCC website under the *FRCC PC Member List* (pursuant to 6.2.4).

The *Rules of Procedure for FRCC Standing Committees'* document on the FRCC website describes the FRCC PC structure and processes as they relate to Organization Structure, Standing Committee Representation, Standing Committee Quorum and Voting, Duties of Officers and Representatives, General Procedures for Standing Committees, FRCC Representation on NERC Committees, Procedures of Minutes of Meetings and Conduct of the Meeting.

If an interested entity is an FRCC member, they may participate in the committees via participation within one of the identified sectors (Supplier Sector, Non-Investor Owned Utility Wholesale Sector, Load Serving Entity Sector (including municipals and cooperatives), Generating Load Serving Entity Sector, Investor Owned Utility Sector, and General Sector (this sector provides for any entity or individual's participation)). If a party is not a member, they may participate in open committee meetings that are scheduled as part of the BTPP process. Moreover, at the FRCC regional level interested stakeholders have an opportunity to raise any special requirements that they have and believe have not been addressed at the local level.

Customer input is included in the early stages of the development of the transmission plans, as well as during and after plan evaluation processes. Detailed evaluation and analysis of the transmission owners'/providers' plans are conducted by the FRCC subcommittees under the direction of the FRCC PC. Such evaluation and analysis provides the basis for possible changes to the transmission owners'/providers' plans that could result in a more reliable and more robust transmission system for the FRCC Region. The FRCC PC meets on a regular basis, usually monthly, with two weeks prior notice.

6.2.1 Meetings

The FRCC meeting dates are provided in the *FRCC Calendar* document on the FRCC website and the chairs and member representatives for the various committees are posted on the FRCC website under the *FRCC Committees* (pursuant to 6.2.4). The meeting agenda for the FRCC PC is normally provided two weeks prior to the meeting to the committee members.

FRCC meeting notices, meeting minutes and documents of FRCC PC and/or FRCC Board meetings in which transmission plans or related study results will be exchanged, discussed or presented, are distributed by the FRCC.

6.2.2 Standards of Conduct

The FRCC has developed the *FERC Standards of Conduct Protocols for the FRCC* ("Standards of Conduct Protocols") document for the purpose of ensuring proper disclosure of transmission information in accordance with FERC requirements. The primary rule is that a transmission provider must treat all transmission customers, affiliated and non-affiliated on a non-discriminatory basis, and it cannot operate its transmission system to give a preference to any transmission customer or to share non-public transmission or customer information with any transmission customer.

The rules also prevent transmission function employees from sharing with their merchant employees and certain affiliates non-public transmission information about the transmission provider's transmission system or any other transmission system, which is information that the affiliated merchant employee receiving the information could use to commercial advantage. All documents created by, or for, the FRCC that contain non-public transmission information shall be handled consistent with the Standards of Conduct Protocols.

6.2.3 Rules of Procedure

The FRCC conducts the planning process in an open manner in such a way that it ensures fair treatment for all customers, stakeholders, owners and operators of the transmission system. Stakeholders have access to and participate in the FRCC planning process, as described in this document. The committees and subcommittees described in this document are stakeholder groups. The FRCC PC consists of six stakeholder sectors: Suppliers, Non-Investor Owned Utility Wholesalers, Load Serving Entities, Generating Load Serving Entities, Investor Owned Utilities, and General. The rules of procedure governing the FRCC PC in conducting this *FRCC RTPP* are posted under the *Rules of Procedure for FRCC Standing Committees* on the FRCC website.

The FPSC is encouraged to and does participate in the *FRCC RTPP*.

6.2.4 Confidential / Proprietary Information and CEII

This FRCC RTPP provides for the overall protection of all confidential and proprietary information that is used to support the planning process. A customer, stakeholder or other interested entity may enter into a confidentiality agreement with the FRCC and/or applicable transmission provider/owner, as appropriate, to be eligible to receive transmission information that is restricted due to Critical Energy Infrastructure Information ("CEII"), security, business rules and standards and/or other limitations. The FRCC procedure for requesting this type of information is delineated at the FRCC website under the *Request for FRCC Transmission Information* document.

6.3 Transparency

Providers, performing their local area planning processes, utilize the FRCC databanks as the base case for their studies. The FRCC databanks contain information provided by the FRCC member transmission providers and customers of projected loads, as well as all planned and committed transmission and generation projects, including upgrades, new facilities and changes to planned-in-service dates over the planning horizon. Within their local area planning processes, transmission providers make available to a transmission customer the underlying data, assumptions, criteria and underlying transmission plans utilized in their study processes.

Once the results of the transmission providers' local area planning processes are reflected in the FRCC's initial transmission plan, the FRCC seeks input and feedback from transmission customers and stakeholders for any issues or concerns that are identified and independently assesses the initial regional transmission plan from a FRCC regional perspective. A dialogue among the FRCC, transmission customers, stakeholders, and transmission owners/providers occurs within these planning processes to address any issues identified during the various steps.

When the FRCC regional transmission plan has been approved by the FRCC PC, it is sent to the FRCC Board for approval. After the FRCC Board approves the FRCC regional transmission plan, it is posted on the FRCC website and the FRCC sends notice to the FPSC that the final regional transmission plan is available for their use and review upon request.

Additionally, the FRCC compiles all of the individual transmission providers'/owners' FERC Form 715s within the FRCC region and files all FERC Form 715s on behalf of its members with the FERC on an annual basis.

6.3.1 Reliability Standards and Criteria

Studies conducted pursuant to this RTPP utilize the applicable reliability standards and criteria of the FRCC and NERC that apply to the Bulk Power System as defined by NERC. Such studies also utilize the specific design, operating and planning criteria used by FRCC transmission owners/providers. The transmission planning criteria are available to all customers and stakeholders. Transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process.

The FRCC subcommittees update and distribute transmission projects/upgrades project descriptions, scheduled in-service dates, and project status on a regular basis, no less than quarterly to the FRCC PC. The FRCC also updates and distributes on a periodic basis the load flow database. The FRCC prepares and posts system impact study schedules so that other potentially impacted transmission owners/providers can assess whether they are affected and elect to participate in the study analysis. The FRCC planning studies are also distributed by the FRCC and updated as needed. All entities that have transmission projects/upgrades in the regional transmission plan shall provide updates on such projects at least annually.

6.3.2 Additional Reports and Documents

The FRCC also produces the following annual reports which are submitted or made available to the FPSC. These reports and documents are also available to customers, stakeholders or other transmission owners/providers through the Information Exchange discussed in Section 6.4 below:

a. The Regional Load and Resource Plan contains aggregate data on demand and energy, capacity and reserves, and proposed new generating unit and transmission line additions for Peninsular Florida as well as statewide.
b. The Reliability Assessment is an aggregate study of generating unit availability, forced outage rates, load forecast methodologies, and gas pipeline availability.
c. The Long-Range Transmission Reliability Study is an assessment of the adequacy of Peninsular Florida's bulk power and transmission system. The study includes both short-term (1-5 years) detailed analysis and long-term (6-10 years) evaluation of developing trends that would require transmission additions or other corrective action. Updates on

regional areas of interest and/or constraints (e.g., Central Florida) are also addressed.

6.4 Information Exchange

Transmission providers participate in information exchange on a regular and ongoing basis with the FRCC, neighboring utilities, and customers. Transmission customers are required to submit data to the transmission providers in order to plan for the needs of network and point-to-point customers. Such data/information includes: load growth projections, planned generation resource additions/upgrades (including network resources), any demand response resources, new delivery points, new or continuation of long-term firm point-to-point transactions with specific receipt (i.e., source or electrical location of generation resources) and delivery points, (i.e., the electrical location of load or sink where the power will be delivered to), and planned transmission facilities.

The transmission providers utilize the information provided in modeling and assessing the performance of their systems in order to develop a transmission plan that meets the needs of all customers of the transmission system. The transmission providers exchange information with transmission customers to provide an opportunity for them to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration by their transmission provider. Through this information exchange process, the transmission customers have an integral role in the development of the transmission plan. Consistent with the transmission providers' obligation under federal and state law, and under NERC and FRCC reliability standards, the transmission providers are ultimately responsible for their transmission plans.

6.4.1 FRCC Databank Development

The TTS sets the schedule for data submittal and frequency of information exchange which starts at the beginning of each calendar year. Updates and revisions are discussed at the FRCC PC meetings by the members. This process requires extensive coordination and information exchange over a period of several months as the FRCC develops electric power system load-flow databank models for the FRCC Region. The models include data for every utility in peninsular Florida and are developed and maintained by the FRCC.

The TTS is responsible for developing and maintaining power flow base cases. The FRCC power flow base case models contain the data used by the FRCC and transmission providers for intra- and inter-regional assessment studies, and other system studies. The models created also are the basis for the FRCC submittal to the NERC Multiregional Modeling Working Group ("MMWG"). TTS members support the data collection requirements and guidelines related to the accurate modeling of generation, transmission and load in the power flow cases. The *FRCC Load Flow & Short Circuit Data Bank Procedural Manual* provides the guidelines and procedures adopted for the load flow and short circuit databank development and maintenance efforts. They are intended to provide consistency in data submittals, improve coordination among developers and users of the databank, and increase understanding of the modeling assumptions used.

The FRCC maintains databanks of all FRCC members' projected loads and planned and committed transmission and generation projects, including upgrades, new facilities, and changes to planned in-service dates. These databanks are updated on a periodic basis. The FRCC maintains and updates the load flow, short circuit, and stability models. All of this above information is distributed by the FRCC, along with the FRCC transmission planning studies, subject to possible redaction of user sensitive or critical infrastructure information consistent with market and business rules and standards.

6.4.2 Transmission Developer Interconnection Requests

Any transmission developer that is not participating in the regional transmission planning process (and therefore not seeking regulated cost-of-service recovery) that proposes to develop a transmission project in the FRCC region shall provide to the FRCC PC and affected transmission providers in the FRCC region such information and data related to its proposed project that are necessary to allow the FRCC PC and affected transmission providers in the FRCC region to assess the potential reliability and operational impacts of the non-participant developer's proposed transmission facility on the transmission system in the region. That information should include: transmission project timing, scope, network terminations, load flow data, stability data, HVDC data (as applicable), and other technical data necessary to assess potential impacts.

The required information and data shall be provided with the transmission developer's interconnection request(s). Non-participant developers' transmission projects will not be included in long-term planning models or interconnected to the existing transmission system until and unless: 1) interconnection service has been requested of affected transmission provider(s); and 2) all interconnection studies have been completed.

7.0 Regional Transmission Planning Process Overview

Study Process

Studies conducted pursuant to this RTPP shall utilize the applicable criteria for NERC Reliability Standards and FRCC standards to the BES. Such studies shall also utilize the specific design, operating and planning criteria used by the transmission owners/providers to the extent these specific design, operating and planning criteria meet NERC and FRCC standards and criteria for reliability or are more stringent than any applicable NERC and FRCC standards and criteria for reliability.

For purposes of this RTPP, analysis of 69 kV transmission facilities within the region that do not fall under the NERC definition of BES may be included in studies, as though they were included in the NERC BES definition, in order to better coordinate and improve the transmission system in the FRCC Region.

The RTPP begins with the consolidation of the long-term transmission plans of all of the transmission owners/providers in the FRCC Region including any previously approved CEERTS projects. It is the FRCC's expectation that the long-term transmission plans incorporate the integration of new firm resources as well as other firm commitments. This will include modeling of all transmission facilities 69 kV and above or representative equivalents (facilities exempted by NERC or excluded from the BES by NERC definition may be represented by equivalent models).

Detailed evaluation and analysis of these plans will be conducted by the RPS/TTS/SAS/RS as applicable, or any consultants retained by the FRCC, in collaboration with the FRCC Staff, and directed by the FRCC PC. Such evaluation and analysis will provide the basis for potential changes to individual and/or regional transmission system plans that, if implemented, would result in a more reliable, cost effective or efficient transmission system for the FRCC Region.

The assessment of the long-term transmission plan shall be comprehensive and in-depth. While the final recommended plan may not call for the construction of all transmission facilities identified in various sensitivities, the assessment will provide valuable information on the strength of the transmission system to aid in understanding how the system would perform in various situations.

The examination of multiple expected system conditions shall be performed, including an assessment of areas with recurring, significant congestion. As determined by the FRCC PC, these conditions or sensitivities (beyond those sensitivities required by NERC standards) may include any of, but not be limited to, the types listed below:

- Transmission and/or generation facilities unavailable due to scheduled and/or forced outages.

- Weather extremes for summer and winter periods.

- Different load levels (e.g., 100%, 80%, 60%, and 40%) and/or periods of the year (winter, spring, summer and fall).

- Various generation dispatches that will test or stress the transmission system which may include economic dispatch from all generation (firm and non-firm) in the region.

- Reactive supply and demand assessment (e.g., generator reactive limits, power factor, etc.)

- A specific area where a combination/cluster of generation and load serving capability is among various transmission owners/providers in the FRCC that continually experience or is expected in the future to experience significant transmission congestion on their transmission facilities will be reviewed annually and restudied as required. The analysis should reflect the upgrades necessary to integrate new generation resources and/or loads on an aggregate or regional (cluster) basis.

  Additionally, such analysis may include an estimate of the cost of congestion, as appropriate.

- Other scenarios or system conditions as identified by the FRCC PC (e.g., stability analysis)

For the first 5 years of the planning period, a detailed evaluation will be conducted. For years 6 through 10, a more generalized higher-level study will be conducted.

The FRCC PC shall submit a formal report of the assessment and findings, including any recommendations to the Board. The FRCC PC shall also submit formal reports for the assessment and recommendation of CEERTS projects to the Board, as applicable. Such reports shall include action plans that identify:

- Any recommended modifications to transmission owners'/providers' long-term plans that, in the judgment of the FRCC PC, offer worthwhile enhancements to regional transmission grid reliability, including any CEERTS projects.

- The identification of those elements of the recommended plan that cannot be implemented due to the inability to obtain the required commitments of the affected transmission owner(s)/provider(s) and user(s) to implement the plan.

- The identification of an alternative plan that does have the commitment of the affected transmission owner(s)/provider(s) and user(s) with regard to implementation.

- Any minority views expressed by any member of the FRCC PC or Project Sponsor as well as the identification of any unresolved issues.

7.1 Annual Transmission Planning Process

A Regional FRCC Transmission Plan ("Regional Plan") shall be developed on an annual basis using the ATPP. The Regional Plan[2] takes into consideration the TYSPs that are required to be submitted to the FPSC on April 1st of each year.

Any generating or transmission entity not required to submit a TYSP to the FPSC, shall submit its ten-year plan, consistent with the requirements of the FPSC TYSP, to the FRCC on April 1st of each year. Such entity's ten-year plan shall include the generation expansion plans for load serving entities, firm/network use of transmission, and any planned/proposed transmission system changes, including additions, cancellations, deferrals, and retirements, by transmission owners/providers.

The Regional Plan also includes CEERTS projects identified and analyzed through the BTPP that have been approved by the Board. The BTPP runs concurrently with the ATPP.

Step 1

FRCC PC Initiates FRCC Transmission Planning Review and Coordination Process

Transmission owners/providers shall submit to the FRCC PC their latest 10-year expansion plan for their transmission system by every April 30th, including (1) a list of planned transmission projects and their associated in-service dates that provides for all of their firm obligations based on the best available information, and (2) a list of projects that were deferred, or cancelled from the previous 10-year expansion plan's original in-service date, and (3) any transmission facility retirements for inclusion into the load flow databank.

FRCC will post the initial regional transmission plan on the FRCC website consisting of these planned transmission projects along with their previous in-service dates, current in-service dates, and planned facility retirements.

Step 2

Feedback from Transmission Customers/Users/Others of Individual 10-Year Expansion Plan

Transmission customers/users and other affected parties shall submit to the FRCC PC and affected transmission owners/providers any issues or special needs they feel have not been adequately addressed by the applicable transmission owner's/provider's 10-year expansion plan, and the underlying evaluation demonstrating the rationale for their concern.

Step 3

Review and Assessment by the FRCC PC

The FRCC PC shall review and assess the initial regional transmission plan consisting of transmission owners'/providers' plans from an overall FRCC perspective, ensuring that all affected transmission

[2] The "Regional Plan" consists of the Long-Range Study (including operational procedures) approved by the Board and the list of projects included in the Project Information Form ("PIF").

customers'/users' issues have been identified.

The FRCC PC, the transmission owners/providers and the transmission customers/users shall consult, as appropriate, during this period to address the issues of all parties to ensure their due consideration with regard to possible inclusion into the Regional Plan.

The FRCC PC shall address any issue or area of concern not previously or adequately addressed, with emphasis on constructing a robust regional transmission system.

As identified under Information Exchange above, the databank used in the development of the Regional Plan will be updated annually with periodic revisions by the TTS. Members will re-confirm in-service dates for under-construction, planned, proposed and conceptual projects on at least a quarterly basis.

Members will bring to the attention of the TTS any project changes as soon as possible to allow potentially affected parties as much lead time as possible for implementing alternative solutions. Any changes to the databank that could materially impact the Regional Plan, or affected other parties, will be reviewed by the TTS to determine whether the Regional Plan should be revised to reflect those changes.

The TTS shall send the coordinated study (the preliminary Regional Plan) to the FRCC PC for approval. If required prior to approval, the FRCC PC shall form working group(s), as necessary, to address specific matter(s) that require further technical assessment or evaluation.

Step 4

Issuance of Preliminary Regional Plan

The FRCC PC shall issue the preliminary Regional Plan to all FRCC members, and shall identify any proposed modification to the original transmission owner's/provider's plan. The purpose of this step is to receive comments and to identify any remaining unresolved issues.

Step 5

Approval of Regional Plan

The FRCC PC shall present to the transmission owners/providers, affected transmission customers/users, and other FRCC members a general overview and comments on the preliminary Regional Plan, including proposed modifications to each transmission owner's/provider's individual transmission plan.

The FRCC PC shall identify and discuss minority opinions and unresolved issues.

The FRCC PC shall approve the Regional Plan and present it to the Board for its consideration. The Plan may include specific matters that require further technical assessment or evaluation that have been assigned to a working group, and some unresolved issues may still be pending final resolution.

The Board shall take action on the Regional Plan. The resultant Board approved Regional Plan shall be posted on the FRCC public website and the FRCC will send a notice to the FPSC that the final regional transmission plan is available for their use and review upon request.

Step 6

Unresolved Issues

If any member of the FRCC PC eligible to vote has an unresolved issue(s) after the FRCC PC approves the Regional Plan, said member may direct the FRCC PC to present such unresolved issue(s) to the Board at the same time the Regional Plan is presented for approval.

If the Board fails to satisfy the concerns of the party raising the unresolved issue(s), the party may request the matter be set for dispute resolution in accordance with procedures contained within the FRCC Bylaws.

7.2 Biennial Transmission Planning Process

The BTPP is the process by which transmission providers, FRCC Staff, and other FRCC members identify and evaluate whether there are more efficient or cost-effective regional transmission solutions to regional transmission needs relative to the transmission facilities in the Regional Plan and applies to reliability, economic and public policy regional transmission projects. The regional analysis will be initiated in mid-January of odd-numbered years by the RPS, under the direction of the FRCC PC, and shall utilize the standards, criteria, data, models, methods and studies of the local transmission plans, supplemented as necessary. The regional analysis conducted in the BTPP shall determine if there is a solution meeting CEERTS project criteria that could be proposed for regional cost allocation.

The regional analysis shall also include consideration of potential transmission solutions to transmission needs driven by public policy requirements, as such needs are identified. The provisions for stakeholder involvement and input in the regional transmission plan, and the ability to propose CEERTS Projects on their own initiative, as set forth in these steps, are fully applicable to potential transmission solutions due to transmission public policy needs driven by public policy requirements.

Any entity desiring to propose a CEERTS project for regional cost allocation must submit such a CEERTS project to the FRCC no later than June 1st of the first year of the BTPP. The entity proposing a CEERTS project is referred to as the Project Sponsor. The Project Sponsor for a CEERTS project need not be the Project Developer for that project.

In addition to the right of individual entities to submit potential CEERTS projects, the RPS, made up of transmission providers and other interested entities, shall proactively seek out potential CEERTS projects from its analysis of the most recent Board-approved plan. This will occur during the period February through April of the first year of the BTPP cycle.

7.2.1 Proactive Planning for Potential CEERTS Projects

Gather all relevant information relating to the most recent Board-approved plan (e.g., Final Project Information Form (PIF), approved Long Range Study, early project suggestions from interested entities); and request and collect all necessary supplemental information from transmission providers and other entities (e.g., project details and cost estimates for projects identified for potential displacement, list of potentially feasible projects not selected in the initial regional transmission plan).

Analyze the current plan information to identify potential opportunities for CEERTS projects. Seek justification for remedies that do not have projects planned, and synergies with the planned projects that potentially could be modified, combined, or accelerated for a more cost effective or efficient regional transmission solution. The analysis will include comparative load flow studies to evaluate various potential transmission CEERTS projects. For example, comparative load flow studies will be run to identify and evaluate potential CEERTS projects that could displace transmission projects in the initial regional transmission plan.

<u>Alternative Projects</u>

If a potential CEERTS project is identified that addresses a regional reliability or economic transmission need(s) for which no transmission projects are currently planned, an analysis will be performed to identify local and/or alternative transmission project(s) which would also fully and appropriately address the same regional transmission need(s). These local and/or regional alternative transmission project(s) will be identified through comparative load flow studies. The alternative project(s) will be used to determine the Total Estimated Alternative Project Cost Benefit in the CEERTS Project Cost-Benefit Analysis described in Step 5C below.

If a potential regional public policy transmission need has been identified for which no transmission projects are currently planned and for which no CEERTS project has otherwise been submitted for evaluation, an analysis will be performed to identify a potential CEERTS project that would satisfy that regional public policy transmission need in a least-cost manner by evaluating various potential transmission project alternatives.

The RPS develops potential CEERTS project alternatives and solicits project sponsorship from Enrolled Transmission Providers and other entities which may have an interest in sponsoring potential CEERTS projects.

A potential CEERTS project developed by this process will contain the following minimum set of transmission project information:

- General description of the transmission facilities being proposed;
- General path of the transmission lines, if applicable; and
- Transmission systems that would interconnect with the potential CEERTS project.

The FRCC shall post a notice on its website of any potential CEERTS projects identified through this process. Notice shall be posted by May 1st of the first year of the BTPP cycle to provide time for meeting sponsorship requirements by June 1st.

Each identified potential CEERTS project will require at least one sponsor in order to be submitted to the FRCC for consideration. Multiple sponsors of the same project will be considered joint sponsors and shall equally share the required $100,000 deposit, unless the Project Sponsors otherwise mutually agree to a different sharing of the deposit.

Potential CEERTS projects identified in this process shall not have competing sponsors for the same project. An entity that is not a Project Sponsor or joint Project Sponsor of a potential

CEERTS project shall not be eligible to be a developer of that project, unless the Project Sponsor(s) discontinue development of that project.

The Project Sponsor or joint Project Sponsors shall submit the potential CEERTS project for consideration by June 1st of the first year of the BTPP.

7.2.2 Analysis of Sponsored CEERTS Projects

Once potential CEERTS projects with sponsors are proposed for the BTPP, the following steps are carried out under the direction of the FRCC PC:

Step 1

FRCC PC Reviews CEERTS Project Submittals

To be eligible for approval by the Board for inclusion in the Regional Plan, a proposed CEERTS project must meet threshold criteria and the project submittal must include certain elements. The FRCC PC will review CEERTS Project Sponsor submittals and ensure that they meet the threshold criteria, and the minimum submittal requirements within 30-45 days following the submittals.

The following threshold criteria must be met for CEERTS projects:

- Be a transmission line 230 kV or higher and 15 miles or longer; or
- Be a substation flexible AC transmission system ("FACTS") device (e.g., series compensation or static var compensator) designed to operate at 230 kV or more; and
- Be materially different from projects already in the Regional Plan.[3]

Local transmission facilities located solely within a transmission provider's footprint (e.g., Balancing Authority area) that are not selected in the regional transmission plan for purposes of cost allocation cannot qualify as CEERTS projects. Such facilities are the responsibility of the transmission providers to meet reliability needs and/or other obligations within its retail distribution service territory or footprint.

Minimum Requirements for CEERTS Project Submittals:

<u>Project Sponsor Only</u>
Project Sponsors that do not also intend to be a Project Developer of CEERTS projects must submit the following minimum set of information:

- General description of the transmission facilities being proposed;
- General path of the transmission lines; and
- Transmission systems that would interconnect with the proposed CEERTS project.

<u>Project Sponsor/Developer</u>
Project Sponsors that intend to be the Project Developer of CEERTS projects shall so indicate

[3] The FRCC will consider a CEERTS project to be materially different from another CEERTS project if, for example, it displaces a different local project or projects or is not considered a minor adjustment to an existing local or CEERTS project that it is displacing. Minor adjustments could include changes in equipment size, different terminal bus arrangement, or slight change in route.

and shall submit the following information:

- Transmission project technical information
  - Description of the transmission facilities being proposes (e.g., voltage levels);
  - General path of the transmission lines; and
  - Interconnection points with the existing transmission system.
- A cost estimate and a recommended in-service date for the project. A Project Developer may also submit a demonstration of its cost containment capabilities, including any binding agreement to accept a cost cap for the developer's cost of the transmission project if it is selected as a CEERTS project.
- A high-level summary of who will own, operate and maintain the CEERTS project, to the extent available.

A Project Sponsor may also submit any studies and analysis it performed to support its proposed CEERTS project, including the below:

- Reliability impact assessment
- Load flow analysis that demonstrates performance utilizing the FRCC load flow model
  - The Project Sponsor, if not an FRCC member, may obtain this model upon request from the FRCC ("Request for Florida Reliability Coordinating Council (FRCC) Transmission Information" document is posted on the FRCC website).
- Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required. A demonstration through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan.

A deposit of $100,000[4] shall be submitted by the Project Sponsor at the time the project is submitted (e.g., June 1st of the BTPP cycle) for each CEERTS project.

If a submittal is incomplete, the FRCC PC shall inform the CEERTS Project Sponsor in writing within 15 days after the next regularly scheduled FRCC PC meeting of the specific deficiency(ies), and the Project Sponsor shall be given an opportunity, within 30 days, to submit the information required for a complete submittal.

Step 2

FRCC PC Updates FRCC Board and Posts Information on FRCC Website

[4] This deposit will be used for FRCC internal labor costs for analysis of the project as well as any out-of-pocket expenses such as for independent consultants (unexpended amounts shall be refunded, with interest, to the Project Sponsor(s), as applicable). The actual costs incurred by the FRCC to analyze the CEERTS project will be borne by the Project Sponsor and the deposit will be trued up based on the documented cost of the analysis. An accounting of the actual costs of the CEERTS project analysis including an explanation of how the costs were calculated will be provided to the Project Sponsor after the analysis has been completed. Any disputes regarding the accounting for specific deposits will be addressed through the Dispute Resolution Procedures.

At the next Board meeting following the review in Step 1, the FRCC PC shall provide an update to the Board related to all projects that have been submitted and deemed complete. The FRCC PC shall post this information on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information). At that time, the FRCC PC shall also post on the FRCC website (subject to any posting restrictions to protect CEII or other confidential information) any determination that a proposed CEERTS project is not materially different from a project or projects already in the Regional Plan. Such posting will include an explanation of the basis for the determination that the proposed CEERTS project is not materially different.

Step 3

Regional Projects Subcommittee Performs Technical Analysis with Independent Consultant and Drafts Report for the FRCC PC to Inform Board

During the succeeding three to five months following the Board meeting in Step 2 of the BTPP, the FRCC PC will assign the RPS to work together with an independent consultant to conduct a technical analysis for the purpose of either developing CEERTS project information or validating CEERTS project information and analysis provided by the Project Sponsor. Such analysis will be performed in a manner consistent with other technical analyses performed under the direction of the FRCC PC.

A. The development/validation process will either develop the needed CEERTS project parameters or validate the information and analysis provided by the Project Sponsor. This analysis will examine the following:

   1. Transmission project technical information:
      a) Description of the transmission facilities being proposed (e.g., voltage levels);
      b) General path of the transmission lines; and
      c) Interconnection points with the existing transmission system.

   2. Load flow analysis that demonstrates adequate NERC Reliability Standards performance utilizing the FRCC load flow model.

   3. Whether it can be demonstrated through a technical evaluation process that the CEERTS project is equal to or superior to avoided projects from the current regional transmission plan; or equal to or superior to the alternative transmission project(s) that address(es) the same transmission need(s), which alternative must be identified if there are no transmission projects currently planned for the relevant transmission need(s) (refer to **Alternative Projects** in 7.2.1).
      a) The FRCC PC shall verify that the proposed CEERTS project addresses transmission need(s) for which there are no transmission projects currently planned, and that the alternative project(s) to the CEERTS project could also meet such need(s). After the alternative project(s) are verified to meet such needs, the FRCC PC shall request that the entities responsible for the alternative project(s) provide cost information to the FRCC PC to be used in the FRCC PC's analysis.

4. Identification of projects in the regional transmission plan that would be affected or avoided as well as any additional projects that may be required.
    a) The FRCC PC shall request that the entities responsible for the existing project(s) that could be impacted by the proposed CEERTS project, or entities who would be required to implement additional local projects provide cost information to the FRCC PC to be used in their analysis;

5. Cost estimate for the proposed CEERTS project; and

6. In-service date for the project.

B. The FRCC PC will also consider any proposed non-transmission alternatives on a comparable basis with the CEERTS project.

C. The FRCC PC will provide the CEERTS Project Sponsor and stakeholders an opportunity to review and provide input on a report that includes its findings from the technical analysis performed, and then the report will be provided to the Board with a recommendation as to whether the proposed CEERTS project should proceed to Step 4 of the BTPP. The CEERTS Project Sponsor and stakeholders shall be given 15 days to also provide written comments on the report to the Board following the date on which the FRCC PC provides the report and its recommendations to the Board.

Step 4

FRCC Board Reviews CEERTS Report with Project Sponsor(s) and Makes a Determination

Over a period of two-to-three months from receipt of the FRCC PC report and any comments on the report provided by the CEERTS Project Sponsor and stakeholders pursuant to Step 3 of the BTPP, the Board will review the FRCC PC report and any comments received and determine if the CEERTS project should proceed to Step 5 of the BTPP.

The CEERTS Project Sponsor shall be invited to be present and participate in any Board meeting that addresses the FRCC PC report in order to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

If the Board determines that the CEERTS project should proceed to Step 5 of the BTPP, the project(s) may be included as a sensitivity in the ATPP. If a CEERTS Project Sponsor does not agree with the Board's determination, then the Dispute Resolution Procedures in the FRCC Bylaws are available for use by the CEERTS Project Sponsor.

Step 5

Cost / Benefit Analysis Performed and FRCC PC Provides a Report to the FRCC Board

Over a period of two-to-four months from the Board approval of the continuation of the CEERTS project evaluation in Step 4, the process described below will be performed by the FRCC PC under the direction of the Board.

A. A meeting will be organized by the FRCC PC to provide the CEERTS Project Sponsor an opportunity to fully describe its proposed CEERTS project. This meeting is the venue to fully discuss the CEERTS project, taking into account the technical analysis performed by the FRCC PC, as well as any potential revisions, including transmission technical aspects, transmission project costs, and affected projects. This meeting also provides the opportunity for potentially affected transmission providers to discuss these matters. If no developer is a Project Sponsor of the proposed project, then this meeting also provides an opportunity for potential developers to express interest in being considered as the Project Developer of the CEERTS project (if no entity expresses interest as the Project Developer, then the CEERTS project will not move forward and the projects in the Regional Plan that would have been avoided by the CEERTS project will remain in the Regional Plan). If multiple qualified Project Developers express an interest in developing a CEERTS project for which the Project Sponsor does not plan to be the developer, then such developers must each submit, within the 30 days following the meeting held pursuant to this section A, the project information identified in Step 1 above, and these Project Developer proposals will be evaluated in the remainder of the steps identified in Step 5. This forum will enable the CEERTS project to be fully reviewed by all affected parties.

B. The FRCC PC will consider the proposed project in light of the criteria set forth in Step 3 of the BTPP above and as set forth below.

1. A cost-benefit analysis must be performed in accordance with Step 5 of the BTPP, part C for reliability/economic projects by an independent consultant. If the result of this analysis is a benefit-to-cost ratio of greater than 1.00, the CEERTS project will move forward in the process.

2. For a project proposed to meet a public policy transmission need that requires a solution, as verified by the FRCC PC under section 7.3 of the RTPP, the FRCC PC will determine whether the proposed CEERTS project meets the public policy transmission needs identified. There is no cost-benefit analysis performed, except for the validation of the CEERTS project being the least-cost solution. The CEERTS project may be the only solution proposed, in which case it would be accepted in accordance with the project sponsorship model being used within the FRCC. However, in the event there are equally effective alternative CEERTS project solutions that have been proposed to satisfy the public policy transmission needs, then the least-cost CEERTS project would be selected.

The total estimated cost of the CEERTS public policy project is determined by the methodology set forth in section 7.2.2.4 under Step 5C below.

Cost Benefit Analysis

C. CEERTS Project Cost-Benefit Analysis

An independent consultant will be retained to perform a cost-benefit analysis and will issue a written report of findings to the FRCC PC for Project Sponsor and stakeholder review, as set forth in Step 5D. The independent consultant will determine if the benefit-to-cost ratio, which is the sum of the “Total Estimated Avoided Project Cost Benefit,” “Total

Estimated Alternative Projects Cost Benefit" and "Total Estimated Transmission Line Loss Value Benefit" divided by the "Estimated CEERTS Project Cost," is greater than 1.0.

Such analysis will consider estimated costs and benefits for the 10-year period of the planning horizon that is used to prepare the Regional Plan under development at the time the analysis is prepared plus an additional, sequential 10-year period (the "20-year period"). Levelized annual costs and benefits to determine the appropriate revenue requirements will be used and deemed appropriate.

7.2.2.1 Total Estimated Avoided Project Cost Benefit

The Estimated Avoided Project Cost Benefit for each Enrolled Transmission Provider in the FRCC that has one or more projects being displaced by a CEERTS project will be determined by the independent consultant in the below manner. A CEERTS project that was previously selected and included in the most recent Board-approved transmission plan may be displaced by a newly-proposed CEERTS project. If a newly-proposed CEERTS project would displace a previously-approved CEERTS project, the portion of the costs of the newly-proposed CEERTS project associated with the benefits calculated using the costs of the displaced previously-approved CEERTS project would be allocated to the Enrolled Transmission Providers that were allocated the costs for the previously-approved CEERTS project (see Attachment D, Example 4 for a hypothetical example of this cost allocation process).

Each Enrolled Transmission Provider that has one or more projects being displaced is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each project being displaced and indicate in what year each such project would be projected to be in service.

The independent consultant will review each Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the displaced project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and ongoing capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of Enrolled Transmission Providers weighted by their total capitalization ("Enrolled TP Discount Rate"). Each Enrolled

Transmission Provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Avoided Project Cost Benefit" for each Enrolled Transmission Provider's displaced project(s).

All such TP Estimated Avoided Project Cost Benefits will be summed to determine the Total Estimated Avoided Project Cost Benefit.

7.2.2.2 Total Estimated Alternative Projects Cost Benefit

The Estimated Alternative Project Cost Benefit for each Enrolled Transmission Provider in the FRCC that has one or more alternative projects for which a CEERTS project addresses a need for which there are no transmission projects currently planned will be determined by the independent consultant in the below manner. These projects will include those alternative transmission projects to a CEERTS project that were identified under **Alternative Projects** in 7.2.1.

Each Enrolled Transmission Provider that has one or more alternative projects is considered a beneficiary of the proposed transmission facility(ies) and will develop an original installed capital cost estimate for each alternative project and indicate in what year each such project would be needed to be in service.

The independent consultant will review each Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate, depending on which will be used for further calculations, for each year that the alternative project would have been expected to be in service during the 20-year period, but for the CEERTS project. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements for each project will be determined using the average discount rate of Enrolled Transmission Providers weighted by their total capitalization ("Enrolled TP Discount Rate"). Each Enrolled Transmission Provider will provide its discount rate and total capitalization to the independent consultant for purposes of this calculation. Such net present value will be the "TP Estimated Alternative Project Cost Benefit" for each Enrolled Transmission Provider's displaced project(s).

All such TP Estimated Alternative Project Cost Benefits will be summed to determine the Total Estimated Alternative Project Cost Benefit.

7.2.2.3 Total Estimated Transmission Line Loss Value Benefit

The Total Estimated Transmission Line Loss Value Benefit is calculated for each Enrolled Transmission Provider by the independent consultant as follows:

The change in transmission losses caused by the CEERTS project will be determined by the FRCC PC.

The FRCC PC will direct the RPS to run simulations of the approved Regional Plan with all projects, adjusted (if necessary) to include the alternative transmission projects that were identified that would have been needed to satisfy a transmission need for which no transmission projects are in the current transmission plan (see **Alternative Projects** in 7.2.1), to establish base transmission losses for each Enrolled Transmission Provider represented in the plan over the planning horizon. Base case losses will be determined for the years during which the CEERTS project is expected to be in service during the planning horizon, under both peak and off-peak conditions.

The approved transmission plan will then be modified to (1) include a proposed CEERTS project; (2) remove all alternative transmission projects; and (3) adjust or remove any affected or avoided transmission projects in the approved transmission plan as well as add any additional projects that would be required (see BTPP Step 3, Section A.4.a), after verifying that all reliability requirements are met, with the appropriate in-service dates. The modified plan is then analyzed for losses. The CEERTS case losses are determined for each Enrolled Transmission Provider represented in the plan for the years during which the CEERTS project is expected to be in service during the planning horizon, at both peak and off-peak conditions. Enrolled Transmission Providers with reduced losses are beneficiaries of the CEERTS project.

The change in losses for year 10 of the planning horizon will be held constant for years 11-20 of the 20-year period. The change in losses (whether negative or positive) in each year that the CEERTS project is in service for the 20-year period is determined for each Enrolled Transmission Provider.

The value of the change in losses for each Enrolled Transmission Provider will be determined by the independent consultant as follows:

- The independent consultant will use fuel cost and heat rate data from the U.S. Energy Information Administration ("EIA") to value losses.
- The net present value of the value of losses will be determined for each Enrolled Transmission Provider using the Enrolled TP Discount Rate.
- Such net present value will be the "TP Estimated Transmission Line Loss Value Benefit."

The TP Estimated Transmission Line Loss Value Benefit for each Enrolled Transmission Provider will be summed to determine the Total Estimated Transmission Line Loss Value Benefit.

7.2.2.4 Estimated CEERTS Project Cost

The Estimated CEERTS Project Cost is determined using the following formula:

Estimated CEERTS Project Cost = (a) Estimated Developer Cost + (b) Total Estimated Related Local Project Costs + (c) Total Estimated Displacement Costs

(a) The Estimated Developer Cost will be determined by the independent consultant as follows:

The developer of a CEERTS project will provide an original installed capital cost estimate for the developer's project and indicate which year the project is expected to be in service.

The independent consultant will review the developer's original cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for the developer's project, depending on which will be used for further calculations, for the years during which the CEERTS project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the rates of return on equity approved by FERC for the developer or its affiliates (if any); commitments regarding incentive rates; proposed weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirements will be determined using the Enrolled TP Discount Rate. The net present value of these estimated annual revenue requirements shall be the Estimated Developer Cost.

(b) The Total Estimated Related Local Project Cost will be determined as follows by the independent consultant:

Each Enrolled Transmission Provider that will need to construct a local project to implement the CEERTS project will develop an original installed capital cost estimate for each such related local project and indicate what year such project is projected to be in service.

The independent consultant will review the Enrolled Transmission Provider's cost estimate and may determine to use it for further calculations, or may determine that the estimate is unreasonable and issue a revised cost estimate. If the original cost estimate is not used, justification for its rejection will be described in the independent consultant's report.

The independent consultant will calculate a comprehensive annual transmission revenue requirement associated with the original or revised cost estimate for each year that the local project is expected to be in service during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions such as: the Enrolled Transmission Provider's current FERC-approved rate of return on equity (if any); commitments regarding incentive rates; weighted average cost of capital; and on-going capital and operating expenses. The independent consultant will describe any relevant factors and assumptions used in the report.

The net present value of the estimated annual revenue requirement for each local project will be determined using the Enrolled TP Discount Rate. Such net present value will be the TP Estimated Related Local Project Cost.

All TP Estimated Related Local Project Costs will be summed to determine the Total Estimated Related Local Project Cost.

(c) The calculation of Total Estimated Displacement Cost will be performed by the independent consultant as follows:

Any Enrolled Transmission Provider that has incurred, or expects to incur, costs associated with a project that is being displaced by a CEERTS project will provide an accounting to the independent consultant as to the level of its actual and expected expenditure on any displaced projects and any planned mitigation of such expenditures. The independent consultant will review the displacement cost estimate. The independent consultant will estimate the level of displacement costs that the Enrolled Transmission Provider that has expended funds on a displaced project will recover by assuming that the Enrolled Transmission Provider will be permitted to recover 100% of such displacement costs. The independent consultant will calculate an annual transmission revenue requirement associated with the displacement cost estimate for each year so that the displacement costs would be recovered during the 20-year period. In calculating such an estimated revenue requirement, the independent consultant will take into account relevant factors and assumptions and will describe such relevant factors and assumptions used in the report. The net present value of the estimated annual revenue requirements shall be calculated using the Enrolled TP Discount Rate. Such net present value will be the Estimated Displacement Cost.

All such Estimated Displacement Costs will be summed to determine the Total Estimated Displacement Cost.

D. The FRCC PC will provide the CEERTS Project Sponsors and stakeholders an opportunity to review and provide input on a report that includes its findings from the cost-benefit analysis performed that determined how benefits and beneficiaries were identified and applied to a proposed CEERTS project. The report will then be provided to the Board with the FRCC PC's recommendation based upon its review as set forth above. For any CEERTS public policy project(s), this report will include an explanation of why the CEERTS project(s) does or does not provide an opportunity to satisfy the public policy need. The CEERTS public policy analysis is more completely described in section 7.3 below. The CEERTS Project Sponsor and stakeholders shall be given an opportunity to provide written comments on the report to the Board. The CEERTS Project Sponsor shall be invited to be present and participate in any Board meeting that addresses the FRCC PC report to answer questions and to present its views regarding the CEERTS project and the FRCC PC report.

E. The Board will review the FRCC PC report and any comments on the report that may be provided by the CEERTS Project Sponsor and stakeholders and determine if the proposed CEERTS project is a more cost effective or efficient solution to regional transmission needs under applicable criteria in Step 5 and in section 7.3 Public Policy Planning, as applicable.

F. If a CEERTS project is selected, the FRCC will perform analyses to determine whether the CEERTS project could potentially result in reliability impacts to the transmission system(s) in another transmission planning region. If a potential reliability impact is identified, the FRCC will coordinate with the public utility transmission providers in the other transmission planning region on any further evaluation. The evaluation may identify required upgrades in the other transmission planning region.[5]

Step 6

With Board approval, Transmission Project Developer Selection process is initiated. CEERTS project selection finalized and included in FRCC Regional Plan

Over a period of two-to-three months following a decision that a CEERTS project should move forward under Step 5 of the BTPP, the following "Transmission Project Developer and Project Selection Process" will occur:

A. If the CEERTS project requires upgrades[6] to an Enrolled Transmission Provider's existing facilities, that Enrolled Transmission Provider retains a right of first refusal to build those portions of the CEERTS project.

B. If a single Project Sponsor is also the developer identified for a given CEERTS project, then that Project Sponsor/Developer is accepted by default as the Project Developer eligible to use the regional cost allocation for that CEERTS project (subject to the qualifications review below). If there are different proposed CEERTS projects to address the same transmission need(s), then the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in Step 5C, and once a Project Sponsor's/Developer's proposed CEERTS project is selected in the regional transmission plan, that Project Sponsor/Developer will also be selected as the Project Developer eligible to use the regional cost allocation for that CEERTS project. CEERTS projects proposed by

[5] Neighboring Transmission Planning Region Potential Cost Impacts Not Included in FRCC's CEERTS Cost: The costs associated with any required upgrades identified through the FRCC's CEERTS project evaluation process identified in Step 5F for the neighboring transmission planning region will not be included in the CEERTS cost within the FRCC. However, nothing in this RTPP prevents the beneficiaries or Project Sponsor of a CEERTS project that causes the need for upgrades in another region from voluntarily negotiating a resolution of the project impacts with the transmission owner(s) in the other region.

[6] As used in this section the term "upgrade" means an improvement to, addition to, or replacement of a part of an existing transmission facility; the term does not refer to an entirely new transmission facility. Nothing herein affects an Enrolled Transmission Provider's rights under state law with regard to its real property (including rights-of-way and easements).

a single qualified Project Developer and selected by the FRCC Board will not be assigned to a different Project Developer.

C. If there are multiple Project Developers for the same CEERTS project, then the FRCC Board will, upon request, facilitate an opportunity for the Project Sponsors/Developers to collaborate with each other to determine how each of the Project Developers may share responsibility for portions of the CEERTS project(s). If agreement is reached, then these Project Sponsors/Developers will be selected (subject to the qualifications review in Attachment B). If there is no agreement, then the Project Developer for the CEERTS project will be selected based on the highest benefit-to-cost ratio as determined in Step 5C.

Approval and Certification after Conclusion of the Project Developer Determination and Qualifications Review

At the next Board meeting after successful completion of the items in the steps 1 through 6C above and the Project Developer Determination and Qualification Review (Attachment B), the Board will notify the Project Developer to proceed with the project as it has been approved for inclusion in the regional transmission plan. It is at this point that any transmission projects currently in the regional transmission plan that are being avoided due to the new CEERTS project will be removed from the regional transmission plan and associated regional models. The Project Developer(s) shall then proceed with obtaining the necessary approvals and/or permits required to construct, own and operate the project including certification under the Florida Transmission Line Siting Act.

Process Summary

As identified in this BTPP process, proposed new CEERTS projects are to be submitted by June 1st of the first year of each biennial regional project's planning cycle. The technical evaluation of a new CEERTS project will occur within approximately 12 months concurrent with the evaluation of the initial FRCC regional transmission plan, and final approval will be achieved within 19 months. This time period may be shorter for some CEERTS projects, such as where the project is relatively small in scale.

Following the evaluation steps identified in this BTPP process for a newly proposed CEERTS project, a Project Sponsor can expect the project to be analyzed with the regional transmission plan in the summer or fall of the following year. For the project to remain in the regional transmission plan, the remainder of the process must be completed. For example, a new CEERTS project that was proposed by June 1st in the biennial year 1 would proceed through Step 3 in the fall of biennial year 1 through the winter of biennial year 2. In the following spring and summer of biennial year 2, the project would progress through the items in Step 5 and be added to the regional transmission plan. Successful completion of the items in Step 5 would qualify the project for final approval in December of biennial year 2, roughly 19 months after it was initially proposed.

This overall schedule provides a roadmap of the projected schedule for new CEERTS' project evaluation, selection, approval and ultimate reflection in the regional transmission plan within the mandatory two-year (biennial) planning cycle. A particular CEERTS project submittal may benefit from schedule flexibility or shortening of process steps depending on the project's nature or complexity, availability of qualified Project Developer(s), or other factors. In all cases, once a

CEERTS project is submitted, the FRCC will keep all parties informed of the projected schedule for project evaluation.

This CEERTS project evaluation process will fold into the overall regional transmission planning cycle, which will continue to be an annual process, that is, a regional transmission plan will continue to be developed each year. The inclusion of the CEERTS projects into the annual regional transmission plan will be in accordance with the process outlined above.

After a CEERTS project is approved for the regional transmission plan, the Project Developer shall submit to the FRCC PC a development schedule that sets forth the required steps necessary to develop and construct the project and the schedule that the developer will follow to satisfy each required step. Required steps include, but are not limited to, obtaining all regulatory approvals necessary to develop and construct the facility.

Status updates of a CEERTS project are required to the FRCC PC at any time when material changes to the project or schedule take place, or at least annually, and must include any revised cost estimate. If the cost estimate for a CEERTS project is substantially more than the cost estimate upon which the project was approved, the FRCC PC and Board may re-examine the cost effectiveness of the project.

If a CEERTS reliability-based project is abandoned by the developer, the transmission provider(s) has a right of first refusal to complete the project to the extent it is located in the transmission provider's service territory. However, if the transmission provider decides not to complete the abandoned reliability-based CEERTS project and decides instead to propose an alternative CEERTS project, then other potential developers will be given an opportunity to propose an alternative CEERTS project to ensure that the reliability need is met. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed. If a non-reliability-based CEERTS project is abandoned by the developer, other potential developers may offer to complete the project. Developer evaluation and selection shall follow the steps above for a CEERTS project when first proposed.

If a delay in the completion of a CEERTS reliability-based project potentially would cause a transmission provider or other NERC-registered entity to violate a Reliability Standard, the NERC-registered entity shall inform the FRCC PC as soon as it is aware of the possibility. The FRCC PC will re-evaluate the regional transmission plan to determine if the delay in the CEERTS project requires the evaluation of alternative solutions to ensure the relevant transmission provider or other NERC-registered entity can continue to meet its reliability and/or other service obligations. If the FRCC PC determines that the delay in the CEERTS project would adversely affect reliability (e.g., would cause a violation of one or more NERC reliability standards), the FRCC PC will initiate a process to evaluate solutions to address the reliability concerns.

The transmission providers whose system(s) are affected by these reliability concerns will be given an opportunity to propose solutions that they would implement within their service territories or footprints to address these reliability concerns and their proposals can be evaluated as possible CEERTS projects if such transmission providers agree. The FRCC PC will fully evaluate the original CEERTS project delay along with any proposals for alternate solutions and will make a determination on how to proceed in a timely manner to ensure that the FRCC Regional Plan supports the adequate planning for a reliable transmission system for the FRCC region. Where possible, the review of a CEERTS project delay will be included within the BTPP cycle. However, if the FRCC PC determines that a CEERTS project delay needs to be evaluated outside of the BTPP cycle, the FRCC PC will notify the members and establish a schedule for the evaluation process. The FRCC PC will follow similar steps as described above to develop a report of the results of their evaluation and provide their findings to the Board for ultimate resolution.

The FRCC PC, under the oversight of the Board, will verify that all required reliability, operational, and property rights provisions listed below are in place, or reasonably planned for, after a CEERTS project is included in the Regional Plan. The Board will monitor such elements and progress toward such elements in determining whether a CEERTS project has been delayed or abandoned, including:

- All certification and other requirements under the NERC Standards and Rules of Procedure;
- Implementation of communications and operational control features (e.g., requirements to follow instructions of the Reliability Coordinator, Balancing Authority and/or Transmission Service Provider);
- Responsibility for operation and maintenance ("O&M"), including any plans to turn over O&M responsibilities to another entity; and
- Acquisition of the property rights necessary to construct the CEERTS facilities, or a reasonable expectation of the ability to acquire such rights.

7.3 Public Policy Planning

To be considered in transmission planning, a public policy requirement must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency). If a stakeholder identifies a transmission need that is driven by a public policy requirement, it must submit a written description of the need to the FRCC PC, prior to January 1st of the first year of the BTPP cycle for consideration in regional planning during that planning cycle. To the extent the information is available to the stakeholder, the description of the need should:

- identify the state, federal, or local law or regulation that contains the public policy requirement;
- identify the type of entity(ies) in the region to which the public policy requirement applies;
- identify the subset of entities in the region subject to the public policy requirement that have a transmission need driven by the public policy requirement;
- describe the type and nature of the transmission service, including the number of megawatts, needed from the Enrolled Transmission Providers by such subset of entities, to meet that transmission need.

Any stakeholder submitting a potential public policy transmission need to the FRCC PC may, but is not required to, also propose a transmission project(s) to meet such a need along with its description of the need. All submissions will be posted on the FRCC website for public comment and will be reviewed to determine if a public policy requirement is driving a transmission need for which a solution is required. The FRCC PC, under the oversight of the Board, may seek, on a voluntary basis, additional information from entities identified as having potential needs and then will evaluate the submittals and any additional information to make a decision as to whether a public policy requirement is driving a transmission need for which a solution is required and will post its determination on the FRCC website prior to March 1st of the first year of the BTPP cycle, along with an explanation and record of that determination (including a negative determination). If a public policy transmission need is identified for which a transmission solution is required, CEERTS and local projects shall be proposed as part of the BTPP to address such a need.

8.0 Interregional Transmission Coordination Procedures

The FRCC through this RTPP, coordinates with the public utility transmission providers in the Southeastern Regional Transmission Planning process region ("SERTP") to address transmission planning coordination issues related to interregional transmission facilities. These Interregional Transmission Coordination Procedures ("ITCP") include a detailed description of the process for coordination between the FRCC and the SERTP (on behalf of the public utility transmission providers); (i) with respect to an interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than transmission facilities included in the regions' respective regional transmission plans. The ITCP are provided in this RTPP with additional materials provided on the regional planning websites.

The following requirements are included in the ITCP:

(1) A commitment to coordinate and share the results of the FRCC and SERTP regional transmission plans to identify possible interregional transmission projects that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) A duty to exchange, at least annually, planning data and information; and

(4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The transmission providers in the FRCC have worked with transmission providers located in the SERTP to develop a mutually agreeable method for allocating between the two transmission planning regions the costs of new interregional transmission facilities that are located within both transmission planning regions. Such cost allocation method satisfies the six interregional cost allocation principles set forth in Order No. 1000 as approved by the FERC and is included in this RTPP.

Interregional Transmission Planning Principles

Representatives of the FRCC and the SERTP will meet no less than once per year to facilitate the ITCP described below (as applicable). Representatives of the FRCC and the SERTP may meet more frequently during the evaluation of project(s) proposed for purposes of interregional cost allocation between the FRCC and the SERTP.

8.1 Coordination

8.1.1 **Review of Respective Regional Plans:** Biennially, the FRCC and the SERTP shall review each other's current regional plan(s) and engage in the data exchange and joint evaluation described in Sections 8.2 and 8.3.

8.1.2 **Review of Proposed Interregional Projects:** The FRCC and SERTP will coordinate with regard to the evaluation of interregional transmission projects identified by the FRCC and SERTP as well as interregional transmission projects proposed for Interregional Cost

Allocation Purposes ("Interregional CAP"), pursuant to Sections 8.3 and 8.4, below. Initial coordination activities regarding new interregional proposals will typically begin during the third calendar quarter. The FRCC and the SERTP will typically exchange status updates for new interregional transmission project proposals or proposals currently under consideration every six (6) months, or as needed. These status updates will generally include, if applicable:

- an update of the region's evaluation of the proposal;
- the latest calculation of Regional Benefits (as defined in Section 8.4.2);
- the anticipated timeline for future assessments; and
- re-evaluations related to the proposal.

8.1.3 **Coordination of Assumptions Used in Joint Evaluation:** The FRCC and SERTP will coordinate assumptions used in joint evaluations, as necessary, which includes items such as:

- Expected timelines/milestones associated with the joint evaluation;
- Study assumptions; and
- Regional benefit calculations.

8.2 Data Exchange

8.2.1 At least annually, the FRCC and the SERTP shall exchange power-flow models and associated data used in the regional transmission planning processes to develop their respective then-current regional transmission plan(s). This exchange will typically occur by the beginning of each region's transmission planning cycle. Additional transmission-based models and data may be exchanged between the FRCC and SERTP as necessary and if requested. For purposes of the interregional coordination activities outlined in this RTPP, only data and models used in the development of the FRCC's and SERTP's then-current regional transmission plans and used in their respective regional transmission planning processes will be exchanged. This data will be posted on the pertinent regional transmission planning process' website, consistent with the posting requirements of the respective regional transmission planning processes, and is considered CEII. The FRCC shall notify the SERTP of such posting.

8.2.2 The FRCC regional transmission plans will be posted on the FRCC website pursuant to the FRCC's RTPP. The FRCC will also notify the SERTP of such posting so the public utility transmission providers in the SERTP may retrieve these transmission plans. The SERTP will exchange their then-current SERTP regional plan(s) in a similar manner to the FRCC according to their regional transmission planning process.

8.3 Joint Evaluation

8.3.1 **Identification of Interregional Projects:** After the FRCC and SERTP have exchanged planning models and data and current regional transmission plans as described in Section 8.2, the FRCC and, the SERTP will review one another's then-current regional plan(s) in accordance with the coordination procedures described in Section 8.1 and their respective regional transmission planning processes. If through this review, the FRCC or SERTP identify a potential interregional project that could be more efficient or cost effective than projects included in the respective regional plans, the FRCC and SERTP will jointly evaluate the potential project pursuant to Section 8.3.4.

8.3.2 **Identification of Interregional Projects by Stakeholders:** Stakeholders may also propose projects that may be more efficient or cost-effective than projects included in the FRCC's and the SERTP's regional transmission plans pursuant to the procedures in each region's regional transmission planning processes. The FRCC and the SERTP will evaluate interregional projects proposed by stakeholders pursuant to Section 8.3.4.

8.3.3 **Identification of Interregional Projects by Developers**: Interregional transmission projects proposed for potential Interregional CAP must be submitted in both the SERTP and FRCC regional transmission planning processes. The project submittal must satisfy the requirements of Section 8.4.1. The submittal must identify the potential transmission project as interregional in scope and identify the FRCC and SERTP as regions in which the project is proposed to interconnect. The FRCC will verify whether the submittal for the potential interregional transmission project satisfies all applicable requirements. Upon finding that the proposed interregional transmission project satisfies all such applicable requirements, the FRCC will notify the public utility transmission providers in the SERTP. Once the potential project has been proposed through the regional transmission planning processes in both regions, and upon both regions so notifying one another that the project is eligible for consideration pursuant to their respective regional transmission planning processes, the FRCC and SERTP will jointly evaluate the proposed interregional projects pursuant to Sections 8.3 and 8.4.

8.3.4 **Evaluation of Interregional Projects:** The FRCC and the SERTP shall act through their respective regional transmission planning processes to evaluate potential interregional transmission projects and to determine whether the inclusion of any potential interregional transmission projects in each region's regional transmission plan would be more efficient or cost-effective than projects included in their respective then-current regional transmission plans. Such analysis shall be consistent with accepted planning practices of the respective regions and the transmission study methodologies utilized to produce each region's respective regional transmission plan(s). The FRCC will evaluate potential interregional transmission projects consistent with the BTPP. To the extent possible and as needed, assumptions and models will be coordinated between the FRCC and SERTP as described in Section 8.1. Data exchange to facilitate this evaluation shall use the procedures described in Section 8.2.

8.3.5 **Initial Evaluation of Interregional Projects Proposed for Interregional Cost Allocation Purposes:** If an interregional project is proposed in the FRCC and the SERTP for Interregional CAP, the initial evaluation of the project will typically begin during the third calendar quarter, with analysis conducted in the same manner as analysis of interregional projects identified pursuant to Sections 8.3.1 and 8.3.2. Projects proposed for Interregional CAP shall also be subject to the requirements of Section 8.4.

8.4 Cost Allocation

If an interregional project is proposed for Interregional CAP in the FRCC and the SERTP, then the following methodology applies:

8.4.1 **Interregional Projects Proposed for Interregional Cost Allocation Purposes:** For a transmission project to be considered for Interregional CAP within the FRCC and the SERTP, the following criteria must be met:

A. The transmission project must be interregional in nature;
   - Be located in both the FRCC and the SERTP regions;
   - Interconnect to transmission facilities in both the FRCC and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan(s) that are currently under development; and
   - Meet the threshold criteria for transmission projects potentially eligible to be included in the regional transmission plans for purposes of cost allocation in both the FRCC and the SERTP, pursuant to their respective regional transmission planning processes.

B. On a case-by-case basis, the FRCC and the SERTP will consider a transmission project that does not satisfy all of the criteria specified in Section 8.4.1.A but: (i) meets the threshold criteria for a project proposed to be included in the regional transmission plan for purposes of cost allocation in at least one of the two regions; (ii) would be located in both regions; and (iii) would be interconnected to transmission facilities in both the FRCC and SERTP regions. The facilities to which the project is proposed to interconnect may be either existing transmission facilities or transmission projects included in the regional transmission plan that are currently under development.

C. The transmission project must be proposed for purposes of cost allocation in both the FRCC and the SERTP.
   - Except for the case-by-case exception for project threshold criteria identified in Section 8.4.1.B, the transmission developer and project submittal must satisfy all criteria specified in the respective regional transmission processes.

8.4.2 **Evaluation of Interregional Projects Proposed for Interregional Cost Allocation Purposes:** Interregional projects proposed for Interregional CAP in the FRCC and the SERTP shall be evaluated within the respective regions as follows:

A. Each region, acting through its regional transmission planning process, will evaluate proposals to determine whether the proposed project(s) addresses transmission needs that are currently being addressed with projects in its regional transmission plan and, if so, which projects in the regional transmission plan could be displaced by the proposed project(s).

B. Based upon its evaluation, each region will quantify a Regional Benefit based upon the transmission costs that each region is projected to avoid due to its transmission project(s) being displaced by the proposal.

- For purposes of this ITCP, "Regional Benefit" means the total avoided costs of projects included in the then-current regional transmission plans that would be displaced if the proposed interregional transmission project was included. The Regional Benefit is not necessarily the same as the benefits used for purposes of *regional* cost allocation.

8.4.3 **Calculation of Benefit-to-Cost Ratio:** Each region will calculate a regional benefit-to-cost ("BTC") ratio consistent with its regional process and compare the BTC ratio to its respective threshold to determine if the interregional project appears to be more efficient or cost effective than those projects included in its current regional transmission plan. Each region shall utilize the cost calculation(s) as defined in such region's regional transmission planning process (*e.g.,* the FRCC will compute the cost of the portion of the interregional project that resides within the FRCC region in accordance with their regional process and the SERTP will do the same). The regions shall also coordinate such cost calculation assumptions in accordance with Section 8.1.3. The anticipated percentage allocation of costs of the interregional project to each region shall be based upon the ratio of the region's Regional Benefit to the sum of the Regional Benefits identified for both the FRCC and the SERTP. The Regional Benefits shall be determined pursuant to the methodology described in Section 8.4.2. Regional BTC assessments shall be performed in accordance with each region's regional transmission planning process, including but not limited to subsequent calculations and reevaluations.

8.4.4 **Inclusion in Regional Transmission Plans:** An interregional project proposed for Interregional CAP in the FRCC and the SERTP will be included in the respective regional transmission plans for purposes of cost allocation after:

A. Each region has performed all evaluations, as prescribed in its regional transmission planning process, necessary for a project to be included in its regional transmission plan for purposes of cost allocation;
    - This includes any regional BTC ratio calculations performed pursuant to Section 8.4.3; and

B. Each region has obtained all approvals, as prescribed in its regional process, necessary for a project to be included in the regional transmission plan for purposes of cost allocation.

8.4.5 **Allocation of Costs Between the FRCC and the SERTP:** The cost of an interregional project, selected for purposes of cost allocation in the regional transmission plans of both the FRCC and the SERTP, will be allocated as follows:

A. Each region will be allocated a portion of the interregional project's costs in proportion to such region's Regional Benefit to the sum of the Regional Benefits identified for both the FRCC and the SERTP.

    - The Regional Benefits used for this determination shall be based upon the last Regional Benefit calculation performed – pursuant to the method described in Section 8.4.2. – before each region included the project in its regional transmission plan for purposes of cost allocation and as approved by each region.

B. Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in its regional transmission planning process.

C. Should one region be willing to bear more costs of the interregional transmission project than those costs identified pursuant to the methodology described in Section 8.4.5.A, the regions may voluntarily agree, subject to each regions and the affected transmission providers' approvals, to an alternative cost-sharing arrangement.

8.4.6 **Removal from Regional Plans:** An interregional project may be removed from the FRCC's or the SERTP's regional transmission plan for purposes of cost allocation: (i) if the developer fails to meet developmental milestones; (ii) pursuant to the reevaluation procedures specified in the respective regional transmission planning processes; or (iii) if the project is removed from one of the region's regional transmission plans pursuant to the requirements of its regional transmission planning process.

A. The FRCC shall notify the public utility transmission providers in the SERTP if an interregional project or a portion thereof is likely to be removed from its regional transmission plan.

8.5 Openness and Transparency

The FRCC shall follow the principles enumerated in Section 6.0 of this RTPP. In addition, the FRCC shall perform the following additional tasks for interregional planning:

A. Access to the interregional planning data utilized will be made available through the FRCC website subject to the Standards of Conduct Protocols. The FRCC shall make available on the FRCC website links to where SERTP and its stakeholders can register and obtain necessary agreements for access to FRCC data and documents.

B. The FRCC will provide status updates of the interregional transmission planning activities during their regional transmission planning meetings, FRCC Board meetings and at the FRCC PC meetings. The status updates of interregional activities will include at a minimum:
   - Facilities to be evaluated;
   - Analysis performed; and
   - Determinations/results.

C. FRCC members and stakeholders will have an opportunity to participate and provide input and feedback in either or both of the respective regional transmission planning processes and coordination related to interregional facilities identified, analysis performed, and any determinations/results.

D. The FRCC will post, on the FRCC website, a list of all interregional transmission projects that are proposed for potential selection in a regional transmission plan for purposes of cost allocation in both the FRCC and the SERTP that are found not to be eligible for consideration because they do not satisfy the regional project threshold criteria of one or both of the regions. The FRCC will also post an explanation of the relevant thresholds the proposed interregional project(s) failed to satisfy.

9.0 Document Distribution/Notification Requirements

9.1 Distribution/Notification Timeframe

This document should be distributed within 5 business days of version approval. It shall also be posted publicly on the FRCC website for Order No. 1000 stakeholders.

9.2 NERC Required Distribution/Notification List

None

9.3 Additional Distribution/Notification List

Planning Committee

Regional Projects Subcommittees

Transmission Technical Subcommittee

10.0 References

10.1 *FRCC Reliability Evaluation Process for Generator and Transmission Service Requests (FRCC-MS-PL-054)*

10.2 *FERC Standards of Conduct Protocols for the FRCC*

10.3 *Rules of Procedure for FRCC Standing Committees*

10.4 *Request for FRCC Transmission Information*

10.5 *FRCC Load Flow & Short Circuit Data Bank Procedural Manual (FRCC-MS-PL-029)*

11.0 List of Attachments

Attachment A: Sharing of Certain Transmission Expansion Costs

Attachment B: Project Developer Qualification Criteria and Review

Attachment C: Map

Attachment D: Examples of CEERTS Cost Allocation Methodology

12.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
10/07/2014	1	New Document incorporating existing FRCC Regional Transmission Planning Process with FERC Order 1000	All
10/29/2014	1	FRCC Board of Directors Approval	All
1/23/2015	2	Revised due to OATT update	All
9/18/2015	3	Revised due to final FERC approval of OATT changes for both Regional Planning and Interregional Coordination. Also aligned RTPP with principles as outlined in the OATTs.	All
9/18/2017	4	Updated references from SWG, TWG and RWG to SAS, TTS and RS respectively and updated the GISR process document reference. Added minor grammatical and capitalization edits. Added new document classification verbiage to cover page. Removed classification and effective date fields from page 2.	All
04/07/2020	5	Periodic review. Minor clarifications consistent with member tariff wording	Sec. 6.2.4 and 6.4.3
04/07/2022	6	Periodic review. No substantive edits needed. Update to FRCC address on title page and addition of Document Distribution requirements per latest FRCC Document Control Policy.	Title page and 9.0
08/28/2024	7	Periodic review. No edits.	All

Attachment A: Sharing of Certain Transmission Expansion Costs

The cost allocation provisions contained in this Attachment A relate to cost allocation procedures for specific circumstances as described herein. This document sets forth (i) certain principles regarding the provision of financial funding to Transmission Owners that undertake remedial upgrades to, or expansions of, their systems resulting from upgrades, expansions, or provisions of services on the systems of other Transmission Owners (third-party impacts), (ii) the principles to allocate the cost of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, and (iii) procedures for attempting to resolve disputes among Transmission Owners and other parties regarding the application of such principles. This document shall not apply to transmission upgrades or expansions if, and to the extent that, the costs thereof are subject to recovery by a Transmission Owner pursuant to either FERC Order 2003 or Order 2006.

Cost Allocation for Third-Party Impacts resulting from the FRCC RTPP

FRCC Principles

1. Except for a CEERTS project for which it is not the Project Developer, each Transmission Owner in the FRCC Region shall be responsible for upgrading or expanding its transmission system in accordance with the FRCC Regional Transmission Planning Process consistent with applicable NERC and FRCC Reliability Standards and shall participate, directly or indirectly (as the member of a participating Transmission Owner, e.g., Seminole and FMPA), in the FRCC Regional Transmission Planning Process in planning all upgrades and expansions to its system.

2. If, and to the extent that, the need for a 230 kV or above upgrade to, or expansion of, the transmission system of one Transmission Owner (the "Affected Transmission Owner") is reasonably expected to result from upgrade(s) or expansion(s) to, or new provisions of service on, the system(s) of another Transmission Owner or Transmission Owners (hereinafter "Precipitating Events"), and if such need is reasonably expected to arise within the FRCC planning horizon, the Affected Transmission Owner shall be entitled to receive Financial Assistance (as defined herein) from each other such Transmission Owner and other parties, to the extent consistent with the other provisions hereof. Such upgrade or expansion to the Affected Transmission Owner's system shall hereinafter be referred to as the "Remedial Upgrade." Upgrade(s), expansion(s), or provisions of service on another Transmission Owner's system that may result in the need for a Remedial Upgrade on the Affected Transmission Owner's system for which Financial Assistance is to be provided hereunder include the following Precipitating Events:
    - A new generating unit(s) to serve incremental load
    - A new or increased long-term sale(s)/purchase(s) to or by others (different uses)
    - A new or modified long-term designation of Network Resource(s)
    - A new or increased long-term, firm reservation for point-to-point transmission service

    Specific non-Precipitating Events are as follows: 1) Transmission requests that have already been confirmed prior to adoption of these principles; 2) Qualifying rollover agreements that are subsequently rolled over; 3) Redirected transmission service for sources to the extent the redirected service does not meet the threshold criteria described in Principle 5.a. shown below. Existing flows would not be considered "incremental."; and 4) Repowered generation if the MW output of the facility is not increased, regardless of whether the repowered unit is used more/less hours of the year.

3. Except for a CEERTS project for which it is not the Project Developer and except to the extent that an Affected Transmission Owner is entitled to Financial Assistance from other parties as provided herein, each Transmission Owner shall be responsible for all costs of upgrades to, and expansions of, its transmission system; provided, however, that nothing herein is intended to affect the right of any Transmission Owner or another party from obtaining remuneration from other parties to the extent allowed by contract or otherwise pursuant to applicable law or regulation (including, for example, through rates to a Transmission Owner's customers).

4. Except for a CEERTS project for which it is not the Project Developer, each Transmission Owner shall be solely responsible for the execution, or acquisition, of all engineering, permitting, rights-of-way, materials, and equipment, and for the construction of facilities comprising upgrades or expansions, including Remedial Upgrades, of its transmission system; provided, however, that nothing herein is intended to preclude a Transmission Owner from seeking to require another party to undertake some or all of such responsibilities to the extent allowed by contract or otherwise pursuant to applicable law.

5. Threshold Criteria: The following criteria ("Threshold Criteria") must be satisfied in order for an Affected Transmission Owner to be entitled to receive Financial Assistance from another party or parties in connection with a Remedial Upgrade:

   a. The need for the Remedial Upgrade must result, or have resulted, from a Precipitating Event that causes a change in power flow of at least a 5% or 25 MW, whichever is greater, on a facility of the Affected Transmission Owner that, but for the Remedial Upgrade, is reasonably expected to result in a violation of applicable NERC and FRCC Reliability Standards, as determined through the FRCC RTPP.

   b. All new or upgraded transmission facilities comprising the Remedial Upgrade must have an operating voltage of 230 kV or higher voltage.

   c. The Upgrade Costs of the Remedial Upgrade must exceed $3.5 million. As used herein, the "Upgrade Costs" means the construction costs of the Remedial Upgrade (determined in accordance with FERC's Uniform System of Accounts) plus the identifiable Pre-Construction Costs thereof. As used herein, "Pre-Construction Costs" are costs that are expended in preparation for the construction of a transmission project, incurred up to and including the date the utility completes site-clearing work. Pre-Construction Costs include, but are not limited to: any and all costs associated with preparing, reviewing and defending an application under the Transmission Line Siting Act (TLSA); costs of site, technology and route selection and acquisition; costs of engineering, designing, and permitting; costs of clearing, grading, and excavation; and costs of development of any on-site construction facilities.

6. In order for a Transmission Owner to be entitled to receive Financial Assistance from another party or parties hereunder in connection with a particular Remedial Upgrade, that Transmission Owner must (i) participate, directly or indirectly, in the FRCC RTPP, and (ii) identify itself as an Affected Transmission Owner and identify the subject Remedial Upgrade in a timely manner once it learns of the need for that Remedial Upgrade.
7. The following principles govern the nature and amount of Financial Assistance that an Affected

Transmission Owner is entitled to receive from one or more other parties with respect to a Remedial Upgrade:

a. In the event that it is reasonably determined that the Remedial Upgrade eliminates or defers the need for another transmission upgrade or expansion, then, for purposes of paragraphs 7.b and 7.c below, the Upgrade Costs of the Remedial Upgrade shall be reduced by the reasonably determined net present value of such other upgrade or expansion that will be avoided as a result of the Remedial Upgrade ("Avoided Costs") up to the amount of the net present value of the total cost of the Remedial Upgrade. If, in such event, the Transmission Owner(s) experiencing such Avoided Costs is/are not the Affected Transmission Owner, the Affected Transmission Owner shall be entitled to receive payment from such other Transmission Owner(s) equal to such net present value. The remaining Upgrade Costs of the Remedial Upgrade (i.e., the Upgrade Costs less, if applicable, the Avoided Costs of all Transmission Owners, including the Affected Transmission Owner, in the Transmission Zone; hereinafter the "Net Upgrade Costs") would be allocated 50% to parties in the Transmission Zone in which the Remedial Upgrade occurred on a weighted basis based upon load[1] (see item 7.b. below), and 50% based upon sources of power (see item 7.c. below).

b. The Affected Transmission Owner shall be entitled to receive from other Transmission Owners having load within the Transmission Zone in which the Remedial Upgrade is to be made a payment in an amount equal to (i) 50% of the Net Upgrade Costs of the Remedial Upgrade[2] times (ii) each Transmission Owner's Load Ratio within that Transmission Zone. Such Load Ratio shall be the ratio of the amount in MW of the load served by each Transmission Owner in the Transmission Zone to the sum in MW of all load in that same Transmission Zone.[3] (For these purposes, network customer loads embedded within a transmission provider's service area in the Transmission Zone would not be separately allocated any costs as such loads would be paying their load ratio share of the affected transmission provider's costs).

   Initially, there are six Transmission Zones in the FRCC region, as depicted in Attachment C. These Transmission Zones are subject to modification in the future in specific instances to the extent warranted by circumstances. A request by a party to modify one or more Transmission Zones should be substantiated on its merits (e.g., technical analysis, area of limited transmission capability).

   The following principles will guide how the boundaries of Transmission Zones are determined:

   - Electrically, a substantial amount of the generation within a Transmission Zone is used to serve load also within that Transmission Zone.
   - Transmission facilities in a Transmission Zone are substantially electrically independent of other Transmission Zones.
   - Transmission Zones represent electrical demarcation areas in the FRCC transmission grid that can be supported from a technical perspective.
   - Transmission Zones may be modified by providing a technical showing with the supporting

[1] 100% if transmission expansion not precipitated by a transmission request keyed to sources of power (i.e., generation).
[2] See note 2 above regarding the applicable percentage.
[3] Load refers to the projected average of individual system winter and summer peak loads for all years of the study horizon (e.g., the average of ten values for a five-year study period).

rationale to the FRCC PC for its review and approval. An example of a potential need for a zone change may be that, in order to mitigate an overloaded facility, a transmission upgrade or expansion would extend beyond the pre-established zonal boundaries such that these boundaries would need to be revised to best address this situation.

c. If the Remedial Upgrade shall have been precipitated by one or more transmission service requests keyed to new sources of power (i.e., generation), then the party(ies) requesting such transmission service(s) shall be responsible for providing to the Affected Transmission Owner funding for 50% of the Net Upgrade Costs of the Remedial Upgrade in proportion to the respective Source Ratios. Each Source Ratio shall be a ratio of the amount in MW of the associated incremental resource's flow impact affecting the limiting facility that caused the need for the Remedial Upgrade to the sum in MW of the total flow impact of all such new resources. The incremental resource's flow impact shall be calculated with the new resource at full output, at peak load level, without contingencies, and averaged over the study period.

   If studies determine that multiple transmission service requests keyed to new sources of power contribute to the need for a Remedial Upgrade by an Affected Transmission Owner, a coordinated study will be performed assessing all such sources of power in a cluster type approach. The transmission customers that confirm the associated transmission reservations for those new sources of power will share in the cost responsibility for these Remedial Upgrades.

   Funding of Upgrade Costs provided by a party to an Affected Transmission Owner in accordance with this paragraph 7.c shall be subject to repayment, without interest, by the Affected Transmission Owner as follows: First, during the first ten years following the completion of the Remedial Upgrade, a funding party shall be entitled to receive credits from the Affected Transmission Owner against charges for transmission services provided by the Affected Transmission Owner to that party, up to the value of the funding party's contribution. Such credits will apply to all charges throughout the ten-year period for any uses of transmission services by the funding party of the Affected Transmission Owner's transmission system. Second, at the end of the ten-year period, the Affected Transmission Owner shall repay the funding party the balance (i.e., Upgrade Costs of such party less amounts for which credits shall have been provided), if any, of the amount provided by that party, without interest.

8. Implementation and Dispute Resolution Process:

   a. As soon as practical after a Transmission Owner shall have identified itself as an Affected Transmission Owner because of the need for a Remedial Upgrade, that Transmission Owner and parties whose actions shall have contributed, or are reasonably expected to contribute, to the need for that Remedial Upgrade and which may be responsible for providing Financial Assistance in connection therewith in accordance herewith shall enter into good faith negotiations to (i) confirm the need and cause for the Remedial Upgrade and their respective responsibilities for providing Financial Assistance to the Affected Transmission Owner, and (ii) establish a fair and reasonable schedule and means by which such Financial Assistance is to be provided to the Affected Transmission Owner.

   b. In the event the parties identified in the foregoing paragraph are unable to reach agreement on the determination or assignment of cost responsibility within a sixty-(60) day period, the dispute shall be resolved pursuant to the Dispute Resolution Procedures in the FRCC Bylaws.

c. Nothing in this document is intended to abrogate or mitigate any rights a party may have before any regulatory or other body having jurisdiction.

d. During those circumstances in which this section 8 pertaining to Dispute Resolution Process is being utilized due to parties being unable to reach agreement on the determination or assignment of cost responsibility associated with a Remedial Upgrade(s), the parties shall continue in parallel with the Dispute Resolution Process and the engineering, permitting and siting associated with the Remedial Upgrade(s). The fact that a matter is subject to Dispute Resolution hereunder shall not be a basis for any party being relieved of its obligations under this document.

Cost Allocation for CEERTS Projects

There are three potential sets of CEERTS' project costs that will be allocated: developer costs, related local project costs, and displacement costs. The general principle is to allocate all of the prudently-incurred costs of a CEERTS project to the entities that benefit from the project in proportion to the benefits received, although a CEERTS Project Developer may accept a cost cap for the developer costs, in which case the developer's costs up to the cost cap will be allocated. Cost allocations are determined in terms of percentages, with each beneficiary allocated a percentage of the CEERTS project costs. Entities that receive no benefit from a CEERTS project will not be allocated any project costs.

1. Project beneficiaries for a CEERTS project will be transmission providers within the FRCC region enrolled in the regional planning process (on behalf of their retail and wholesale customers) which will benefit from the project.

2. The cost allocation for CEERTS reliability/economic projects is based on the following formula using terms defined in Step 5 of the BTPP: ((TP Estimated Avoided Project Cost Benefit + TP Estimated Alternative Project Cost Benefit + TP Estimated Transmission Line Loss Value Benefit) / (Total Estimated Avoided Project Cost Benefit + Total Estimated Alternative Project Cost Benefit + Total Estimated Transmission Line Loss Value Benefit)) * Estimated CEERTS Project Cost. The cost allocation dollar amounts calculated here using estimated cost information will further be translated to a percentage for each beneficiary as a ratio of their allocated share of the total estimated cost of the CEERTS project. These percentages will be used to allocate actual CEERTS project costs that are recoverable. Examples of CEERTS project cost allocation are provided in Attachment D, Examples 1 and 2.

3. The costs for CEERTS public policy projects, that are identified through the process described in the "Public Policy Planning" section 7.3 of the RTPP, will be allocated to the Enrolled Transmission Providers whose transmission systems provide access to the public policy resources. The cost allocation for each Enrolled Transmission Provider will be as follows:

   • Individual Enrolled Transmission Provider MWs = number of megawatts of public policy resources enabled by the public policy project for the customers (including Native Load) within their transmission service territory.

- Total MWs = total number of megawatts of public policy resources enabled by the public policy project.

- Individual Enrolled Transmission Provider cost allocation percentage = (Individual Enrolled Transmission Provider MWs/Total MWs).

An example of the CEERTS public policy cost allocation is provided in Attachment D, Example 3. These percentages will be used to allocate actual CEERTS' project costs that are recoverable.

The process to interconnect individual generation resources is provided for under the generator interconnection section of each utility's OATT and not under this process.

Requests for transmission service that originate in a utility's system and terminate at the border shall be handled through that utility's OATT.

Allocation of Transmission Rights

Enrolled Transmission Providers allocated costs of CEERTS projects shall have priority with regard to any transmission rights associated with such projects, in proportion to their respective share of such costs. Any use of the transmission rights allocated to a transmission provider, including use by the transmission provider itself, shall be governed by the transmission provider's Tariff.

Attachment B: Project Developer Qualification Criteria and Review

Project Developer Qualification Criteria and Review

Developers seeking to be qualified to be a CEERTS Project Developer must submit information to demonstrate that they satisfy the qualification criteria so that the Board can review the qualifications and make a determination as to whether a prospective transmission developer satisfies the qualification criteria such that it may propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.

Project Developer Qualification Criteria

1. Demonstration that the Project Developer is technically, and financially capable of (i) completing the CEERTS project in a timely and competent manner; and (ii) operating and maintaining the CEERTS facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project. To support this demonstration, the following information should be provided/shown:

   A. Project Developer's current and expected capability to finance, or arrange financing for the transmission facilities:

      1. Evidence of its demonstrated experience financing or arranging financing for transmission facilities, including a description of such projects (not to exceed ten) over the previous ten years, the capital costs and financing structure of such projects, a description of any financing obtained for these projects through any approved rates, the financing closing date of such project, and whether any of the projects are in default;
      2. Its audited financial statements from the most recent three years and its most recent quarterly financial statement, or equivalent information;
      3. Current credit ratings from Moody's Investor Services and Standard & Poor's, if available;
      4. A summary of any history of bankruptcy, dissolution, merger, or acquisition of the Project Developer or any predecessors in interest for the current calendar year and the five calendar years immediately preceding its submission of information related to affiliated entities;
      5. A summary of outstanding liens against the developer(s); and
      6. Such other evidence that demonstrates its current and expected capability to finance a CEERTS project.

   The Project Developer must identify the portions of this financial data that would need to be treated as confidential information in accordance with the FRCC confidentiality practices and subject to disclosure only to those that have signed a confidentiality agreement.

   B. Total dollar amount of CEERTS' estimated project(s) cost up to which the Project Developer wants to be deemed qualified.

   C. A discussion of the Project Developer's business practices that demonstrate that its business practices are consistent with Good Utility Practices for proper licensing, designing, right-of-way acquisition, constructing, operating and maintaining transmission facilities that will become part of the regional transmission grid. The Project Developer shall also provide the following information for the current calendar year and the previous five calendar years:

1. A summary of any violations of law by the Project Developer found by federal or state courts, federal regulatory agencies, state public utility commissions, other regulatory agencies, or attorneys general; and
2. A summary of any instances in which the Project Developer is currently under investigation or is a defendant in a proceeding involving an attorney general or any state or federal regulatory agency, for violation of any laws, including regulatory requirements.

D. Technical and engineering qualifications and experience;

E. Past history of meeting transmission project schedules;

F. Past history regarding providing construction and maintenance of transmission facilities and/or contracting for the construction and maintenance of transmission facilities;

G. Capability to adhere to standardized construction, maintenance and operating practices;

H. Plans for compliance with all applicable reliability standards:

I. Planning standards that will be used to develop the project: and

J. Plans to obtain the appropriate NERC certifications.

2. An attestation from an officer of the Project Developer stating that the information that is being submitted is true and that the Project Developer will comply with the provisions identified in the qualification data submittal, and will submit a biennial (or more often if the information provided has materially changed) update of the information submitted, accompanied by an attestation from an officer of the Project Developer that the previously submitted information remains correct and has not materially changed since the last attestation, with such attestation to be submitted biennially while that transmission developer has a transmission project under consideration in the FRCC Regional Planning Process, under construction in the FRCC region or in-service within the FRCC region.

3. For joint ventures, partnerships, or other multiple-party developer arrangements, the qualification criteria above will be applied to the designated lead entity, which will be responsible for meeting the qualification criteria. Sharing of such responsibilities with other entities may be achieved contractually between the designated lead entity and its partners.

Project Developer Qualifications Review

1. Project Developers (both incumbent and non-incumbent Project Developers) that are submitting for the first time a qualification application must submit the application and a deposit of $50,000 to the FRCC along with the information identified in the Qualification Criteria as set forth in this Attachment B above. The deposit will be used by the Board to fund the internal FRCC labor cost for application

review, which will be documented, and expenses for the independent consultant for the review described in the next section. Any unexpended amounts from the deposit, including interest, shall be refunded to the Project Developer. The transmission developer will be provided with an accounting of the actual costs and how the costs were calculated. Any disputes related to the accounting for specific deposits shall be addressed under the dispute resolution procedures in the FRCC Bylaws. A Project Developer may be a joint venture or a partnership in which case a lead representative will be designated in the qualification application. Project Developers that already have been found qualified after a review by the FRCC must submit an attestation to maintain their qualification as discussed in above. If sufficient changes, as determined by the FRCC, have been identified in the attestation by a Project Developer which had previously been qualified, then a deposit of $10,000 to the FRCC will be required during the attestation review process. This deposit will be handled in a similar manner as described above for the initial Project Developer qualification review.

2. The Board will provide for the review of the submitted qualifications by an independent consultant. The independent consultant fees will be paid from the deposit made when a Project Developer qualification application is submitted. The independent consultant will make a recommendation to the Board as to whether the Qualification Criteria have been met. The Board shall make, on a non-discriminatory basis, a determination as to whether the Qualification Criteria have been met. If the Board determines that the Qualification Criteria have not been met, the Board will notify the Project Developer of the qualification deficiencies and provide a 30-day period for the Project Developer to cure the deficiencies. If a Project Developer does not agree with the Board's determination, then the FRCC Bylaws Dispute Resolution Procedures are available for use by the Project Developer. The qualification process is a one-time process for each Project Developer, subject to the attestation review process annual update.

3. The timeline for the Project Developer qualification review evaluation process is set forth below:

    a. By January 1st of the first year of a BTPP cycle, any potential developer that seeks to be qualified to develop CEERTS projects during this cycle must submit its qualifications to the FRCC. Biennial attestations also must be submitted at this time.

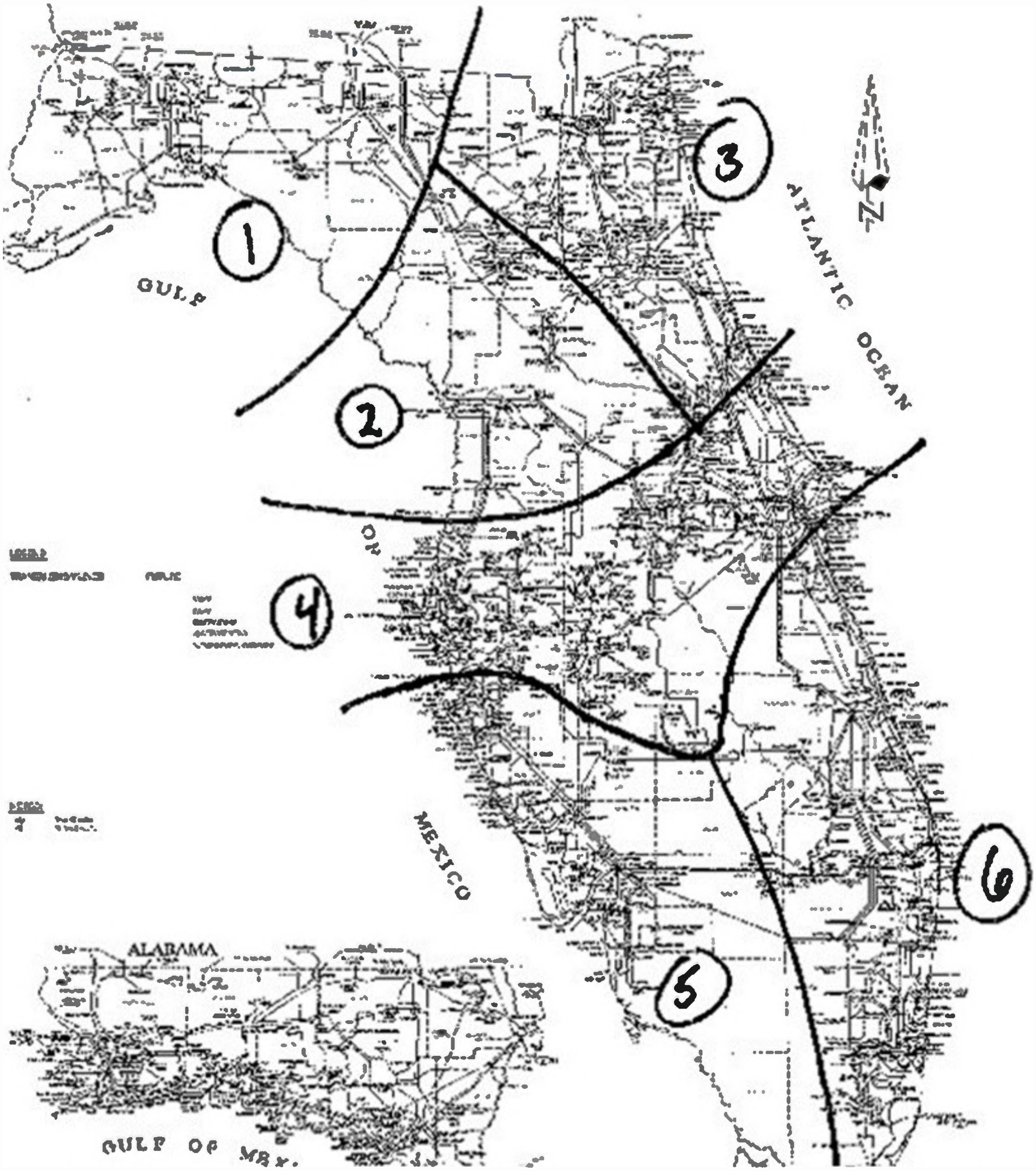
    b. In January through March of the first year of a BTPP cycle, FRCC shall coordinate the qualifications review.

    c. By April 1st of the first year of a BTPP cycle, the Board will inform developers that have submitted qualifications or attestations that they have either met the qualification criteria or the Board will identify deficiencies in the submitted qualifications/attestations.

    d. From April 1st through April 30th of the first year of a BTPP cycle, developers will have an opportunity to cure deficiencies and resubmit their modified qualifications/attestations.

    e. From May 1st through May 31st of the first year of a BTPP cycle, the Board shall reexamine the modified qualifications/attestations, make final determinations, and notify developers, FRCC members and other stakeholders.

Attachment C: Map



Attachment D: Examples of CEERTS Cost Allocation Methodology

Example 1: Reliability/Economic Project

CEERTS project where Enrolled Transmission Providers A, B and C all receive benefits from the project.

The Project Developer is a non-incumbent developer

Assumptions:

Estimated CEERTS Project Cost = $401M:

– Estimated Developer Cost = $400M

– Total Estimated Related Local Project Costs = $1M

Total Estimated Avoided Project Cost Benefit = $500M:

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $300M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200M

– Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $0

Total Estimated Alternative Project Cost Benefit = $0M

Total Estimated Transmission Line Loss Value Benefit = $14M:

– Enrolled Transmission Provider A Estimated Transmission Line Loss Value Benefit = $4M

– Enrolled Transmission Provider B Estimated Transmission Line Loss Value Benefit = $5M

– Enrolled Transmission Provider C Estimated Transmission Line Loss Value Benefit = $5M

Benefit to Cost Ratio:

"(Total Estimated Avoided Project Cost Benefit" ($500M) plus "Total Estimated Alternative

Project Cost Benefit" ($0M) plus "Total Estimated Transmission Line Loss Value Benefit" ($14M)) divided by Estimated CEERTS Project Cost ($401M) = 1.28, therefore this CEERTS project passes the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

(Percentages in this example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = (($300M + $4M) ÷ $514M) = 59%

– Enrolled Transmission Provider B = (($200M + $5M) ÷ $514M) = 40%

– Enrolled Transmission Provider C = (($0 + $5M) ÷ $514M) = 1%

Example 2: Reliability/Economic Project

CEERTS project where Enrolled Transmission Providers A & B each receive avoided cost benefits from the project.

There are no transmission loss benefits.

The Project Developer is a non-incumbent developer

Assumptions:

Estimated CEERTS Project Cost = $400 M:

– Estimated Developer Cost = $400 M

Total Estimated Avoided Project Cost Benefit = $300 M:

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $100 M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $200 M

Total Estimated Alternative Project Cost Benefit = $0M

Benefit to Cost Ratio:

"Total Estimated Avoided Project Cost Benefit" ($300 M) divided by Estimated CEERTS Project Cost ($400 M) = 0.75, therefore this CEERTS project does not pass the benefit to cost ratio threshold.

CEERTS Project Cost Allocation:

– N/A

Example 3: Public Policy Project

CEERTS project where LSEs within Enrolled Transmission Providers A, B and C each receive benefits from the project.

The Project Developer is a non-incumbent developer.

Assumptions:

Public policy CEERTS project enables access to a total of 600 MW of public policy resources

Public policy CEERTS project enables LSEs within Enrolled Transmission Providers A, B and C to access the public policy resources:

– Enrolled Transmission Provider A = 100 MWs

– Enrolled Transmission Provider B = 200 MWs

– Enrolled Transmission Provider C = 300 MWs

CEERTS Project Cost Allocation:

(Percentages in this example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = (100 MW / 600 MW) = 17%

– Enrolled Transmission Provider B = (200 MW / 600 MW) = 33%

– Enrolled Transmission Provider C = (300 MW / 600 MW) = 50%

Example 4: Newly-Proposed CEERTS Project Displacing a Previously-Approved CEERTS Project

Previously-approved CEERTS project was estimated to provide LSEs within Enrolled Transmission Providers A and B benefits

Newly-proposed CEERTS project would displace the previously-approved CEERTS project as well as being estimated to provide LSEs within Enrolled Transmission Provider C benefits from the newly-proposed CEERTS project

The newly-proposed CEERTS project would displace the previously-approved CEERTS project

Previously-Approved CEERTS Project:

Assumptions:

Estimated Previously-Approved CEERTS Project Cost = $75M

Total Estimated Previously-Approved CEERTS Project Avoided Project Cost Benefit = $100M

– Enrolled Transmission Provider A Estimated Avoided Project Cost Benefit = $50M

– Enrolled Transmission Provider B Estimated Avoided Project Cost Benefit = $50M

Previously-Approved CEERTS Project Cost Allocation:

(Percentages in example are rounded to nearest whole percentage)

– Enrolled Transmission Provider A = ($50M / $100M) = 50%

– Enrolled Transmission Provider B = ($50M / $100M) = 50%

Previously-Approved CEERTS Project Displaced by a Newly-Proposed CEERTS Project:

Assumptions:

Estimated Newly-Proposed CEERTS Project = $100M

Total Estimated Newly-Proposed CEERTS Avoided Project Cost Benefit = $125M

- Total Estimated Previously-Approved CEERTS Project Cost Benefit = $75M
- Enrolled Transmission Provider C Estimated Avoided Project Cost Benefit = $50M

Newly-Proposed CEERTS Project Cost Allocation:

(Percentages in example are rounded to nearest whole percentage)

– Previously-Approved CEERTS Project Enrolled Transmission Providers (A & B) = ($75M / $125) = 60%

- This 60% of the cost responsibility would be allocated to Enrolled Transmission Providers A & B:
    - ☐ Enrolled Transmission Provider A = 60% * 50% = 30%
    - ☐ Enrolled Transmission Provider B = 60% * 50% = 30%

– Enrolled Transmission Provider C = ($50M / $125M) = 40%

Exhibit DR-6

Alternative Projects Load Flow Summary Table

REDACTED

[redacted]

REDACTED

[redacted]

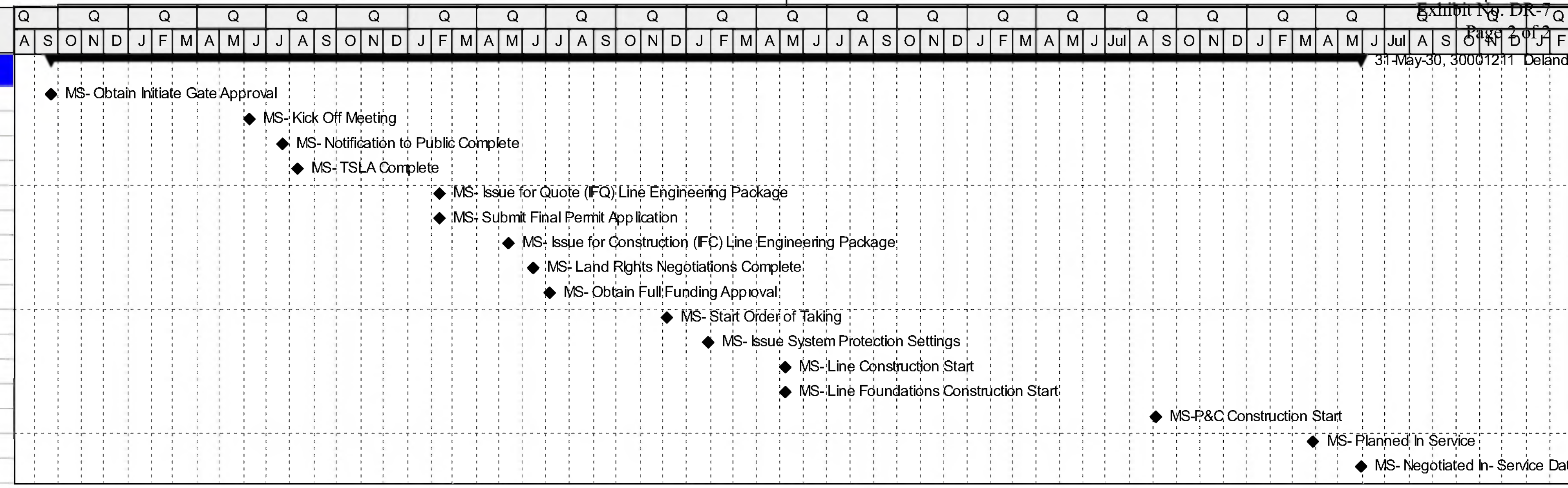
Exhibit DR-7

DeLand West to Dona Vista 230 kV Line Project

Indicative Schedule of Licensing, Design, and Construction

Deland West-Dona Vista - New 230 kV Line | LV - Milestones | 30-Apr-25 16:39

Activity ID	Activity Name	Start	Finish
30001211	Deland West-Dona Vista - New 230 kV Line	22-Sep-25	31-May-30
L20400	MS- Obtain Initiate Gate Approval	22-Sep-25	
L30050	MS- Kick Off Meeting	09-Jun-26	
L30200	MS- Notification to Public Complete		21-Jul-26
L71712	MS- TSLA Complete		11-Aug-26*
L32900	MS- Issue for Quote (IFQ) Line Engineering Package		11-Feb-27
L33900	MS- Submit Final Permit Application		11-Feb-27
L40500	MS- Issue for Construction (IFC) Line Engineering Package		12-May-27
L41605	MS- Land Rights Negotiations Complete		14-Jun-27*
L40600	MS- Obtain Full Funding Approval		06-Jul-27
L71713	MS- Start Order of Taking	06-Dec-27*	
L51300	MS- Issue System Protection Settings		28-Jan-28*
L51100	MS- Line Construction Start	08-May-28*	
L51110	MS- Line Foundations Construction Start	08-May-28*	
L52000	MS-P&C Construction Start	04-Sep-29*	
L60000	MS- Planned In Service		01-Jan-30
L60100	MS- Negotiated In- Service Date		01-Jan-30



Project Baseline Bar | Remaining Work | Milestone
Actual Work | Critical Remaining Work | Summary

Dara Date: 01-Apr-25

TASK filter: Milestone.

Exhibit DR-8

Project Decision Matrix

Exhibit No. (DR-8) - Project Decision Matrix

DECISION STATEMENT: DEF reviewed projects to: (a) improve reliability for DEF customers served from the existing 69 kV circuits between Haines Creek and Piedmont substations; (b) increase east to west power transfer capabilities of the transmission network by providing a new 230 kV circuit between the Volusia and Lake County areas of DEF's territory south of Deland; (c) relieve potential overloads and low voltage conditions under contingency events; and (d) reduce line loading on existing transmission circuits.

ALTERNATIVES: All in-service dates based on the Regional Load Forecast

Selected Project

	Quality Value	In-Service Year / Yes / Score	No / Value*Score	Selected Project / Information
OBJECTIVES		2030		The Deland West to Dona Vista 230kV Project consists of a new 230kV transmission line extending from DEF's Dona Vista substation in Lake County to DEF's Deland West substation in Volusia County.
REQUIREMENTS		**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers		X		Meets all electrical needs.
Alternative plan is feasible to construct		X		Existing corridor and majority of easements already acquired.
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	6	51	Estimated Cost: $165M
Reliability of service to customers	10	10	100	Meets all electrical needs.
Considers long-term flexibility and usefulness	7	10	70	Also rebuilds the 69kV circuits on the existing coridoor.
Minimizes construction difficulties (Includes easements, permits)	9	10	90	Existing corridor and majority of easements already acquired.
Environmental considerations	8	10	80	Existing corridor, environmental impacts minimized.
Impact to customers	9.5	10	95	Existing corridor, impacts limited to customers already in corridor.
TOTAL VALUE SCORE			486	

Alternative 1

	Quality Value	In-Service Year / Yes / Score	No / Value*Score	Alternative 1 / Information
OBJECTIVES		Beyond 2030		The Seneca Lakes to Deland West Project consists of a new 230 kV transmission line extending from DEF's Seneca Lakes substation in Lake County to DEF's Deland West substation in Volusia County. Additionally, two 69kV circuits will be built both from DEF's Seneca Lakes Substation to DEF's Eustis South and Sorrento substations, all located in Lake County.
REQUIREMENTS		**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers			X	This Alternative does not connect the power source to the load as well as the Project.
Alternative plan is feasible to construct		X		New easements required
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	8	68	Estimated Cost: $161M
Reliability of service to customers	10	8	80	This Alternative does not connect the power source to the load as well as the Project.
Considers long-term flexibility and usefulness	7	8	56	The additional 69kV lines being constructed improves the 69kV network.
Minimizes construction difficulties (Includes easements, permits)	9	4	36	New easements required
Environmental considerations	8	6	48	This alternative would require complete greenfield construction through an environmentally sensitive forest. (State lands)
Impact to customers	9.5	4	38	New corridor, new easement impacts to land owners
TOTAL VALUE SCORE			326	

Alternative 2

	Quality Value	In-Service Year / Yes / Score	No / Value*Score	Alternative 2 / Information
OBJECTIVES		Beyond 2030		The Sorrento to Deland West Project consists of a new 230 kV transmission line extending from DEF's Sorrento substation in Lake County to DEF Deland West substation in Volusia County. Additionally, two 69kV circuits will be built both from DEF's Seneca Lakes Substation to DEF's Eustis South and Sorrento substations, all located in Lake County.
REQUIREMENTS		**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers			X	This Alternative does not connect the power source to the load as well as the Project.
Alternative plan is feasible to construct		X		New easements required
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	4	34	Estimated Cost: $171M
Reliability of service to customers	10	8	80	This Alternative does not connect the power source to the load as well as the Project.
Considers long-term flexibility and usefulness	7	8	56	The additional 69kV lines being constructed improves the 69kV network.
Minimizes construction difficulties (Includes easements, permits)	9	4	36	New easements required
Environmental considerations	8	6	48	This alternative would require complete greenfield construction through an environmentally sensitive forest. (State lands)
Impact to customers	9.5	4	38	New corridor, new easement impacts to land owners
TOTAL VALUE SCORE			292	

Alternative 3

	Quality Value	In-Service Year / Yes / Score	No / Value*Score	Alternative 3 / Information
OBJECTIVES		Beyond 2030		The Deland West to Dona Vista 170kV Project consists of a new 170 kV transmission line extending from DEF's Dona Vista substation in Lake County to DEF's Deland West substation in Volusia County
REQUIREMENTS		**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers			X	One single point of failure due to 230/170kV which will potentially create an extended outage of the line.
Alternative plan is feasible to construct		X		Existing corridor and majority of easements already acquired.
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	10	85	Estimated Cost: $159M
Reliability of service to customers	10	4	40	One single point of failure due to 230/170kV which will potentially create an extended outage of the line.
Considers long-term flexibility and usefulness	7	2	14	170kV is non-standard, not capable of relieving loading into North Orlando from Volusia county. Flows on 170kV aren't as high.
Minimizes construction difficulties (Includes easements, permits)	9	8	72	Existing corridor and majority of easements already acquired.
Environmental considerations	8	10	80	Existing corridor, environmental impacts minimized.
Impact to customers	9.5	10	95	Existing corridor, minimal impact to customers
TOTAL VALUE SCORE			386	

Alternative 4

	Quality Value	In-Service Year / Yes / Score	No / Value*Score	Alternative 4 / Information
OBJECTIVES		Beyond 2030		The Deland West -Silver Springs to Dona Vista Project consists of two new 230 kV transmission lines extending from DEF's Dona Vista substation in Lake County to tap into the existing DEF's Deland West substation to Silver Springs in Marion County. This creates two new circuits separately connecting Dona Vista with Deland West and Silver Springs substations.
REQUIREMENTS		**Yes**	**No**	**Information**
Alternative must provide for reliable service to area customers		X		Meets all electrical needs.
Alternative plan is feasible to construct		X		New easements required
DESIRES	**Quality Value**	**Score**	**Value*Score**	**Information**
Cost or economic considerations	8.5	2	17	Estimated Cost: $179M
Reliability of service to customers	10	10	100	Meets all electrical needs.
Considers long-term flexibility and usefulness	7	6	42	This Alternative will not rebuild the 69kV along the Deland West to Dona Vista, which provides less value to the long-term flexibility of this area.
Minimizes construction difficulties (Includes easements, permits)	9	6	54	New easements required
Environmental considerations	8	4	32	This alternative would require complete greenfield construction through an environmentally sensitive forest. National forest (NEPA)
Impact to customers	9.5	4	38	New corridor, new easement impacts to land owners
TOTAL VALUE SCORE			283	