William P. Cox
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Florida Power & Light Company
700 Universe Boulevard
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January 11, 2016

-VIA ELECTRONIC FILING-
Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 150263-EI
Petition for determination of need for Duval-Raven 230 kV transmission line in Baker, Columbia, Duval, and Nassau Counties, by Florida Power & Light Company

Dear Ms. Stauffer:

Please find enclosed for electronic filing on behalf of Florida Power & Light Company's ("FPL") Petition for determination of need for Duval-Raven 230kV transmission line in Baker, Columbia, Duval, and Nassau Counties, and Exhibit A to the Petition. Also enclosed for electronic filing is the testimony and exhibits of FPL witness Francisco Prieto, which support the Petition.

Exhibit A to the Petition and Exhibit FP-3 to Mr. Prieto's testimony contains confidential information. This electronic filing includes only the redacted versions of those documents. Contemporaneous herewith, FPL will file via hand-delivery a Request for Confidential Classification.

If there are any questions regarding this filing, please contact me at (561) 304-5662.

Sincerely,

s/ William P. Cox
William P. Cox
Senior Attorney
Florida Bar No. 0093531

WPC/msw
Enclosure

cc: Leslie Ames, Esq., Office of the General Counsel (via e-mail)
Lee Eng Tan, Esq., Office of the General Counsel (via e-mail)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Duval-Raven 230 kV transmission line in Baker, Columbia, Duval, and Nassau Counties, by Florida Power & Light Company	Docket No. 150263-EI Filed: January 11, 2016

FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR ELECTRICAL TRANSMISSION LINE

Florida Power & Light Company ("FPL"), hereby petitions the Florida Public Service Commission ("Commission") to determine, pursuant to Section 403.537, Florida Statutes (2015), 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, FPL states:

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

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

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

   Florida Power & Light Company
   700 Universe Boulevard
   Juno Beach, Florida 33408

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 FPL:

William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard

Kenneth A. Hoffman
Vice President, Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street

Juno Beach, Florida 33408
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561-304-5662
561-691-7135 (fax)

Tallahassee, Florida 32301
Ken.Hoffman@fpl.com
850-521-3919
850-521-3939 (fax)

4. FPL proposes to construct and operate a 230 kV electrical transmission line as described in Exhibit A attached hereto. The proposed transmission line would originate at FPL's existing Duval Substation in Duval County and would terminate at FPL's planned Raven Substation in Columbia County (the "Duval-Raven Project"). The line has a planned in-service date of December 2018.

5. The Duval-Raven Project is subject to the Transmission Line Siting Act ("TLSA"), Sections 403.52-403.5365, Florida Statutes (2015).

6. Pursuant to the TLSA and Section 403.537, Florida Statutes (2015), and Rules 25-22.075 and 25-22.076, Florida Administrative Code, the Commission has jurisdiction to determine the need for the Duval-Raven Project, applying the standards set forth in Section 403.537(1)(c), Florida Statutes (2015).

7. The information required to be supplied for the need determination pursuant to Rule 25-22.076, Florida Administrative Code, is set forth in Exhibit A hereto and is incorporated herein by reference.

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

9. The data and analyses contained in Exhibit A demonstrate the need for the Duval-Raven 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 residents of this state, the location of the project (starting and ending points of the line), and other relevant matters pursuant to Section 403.537(1)(b), Florida Statutes (2015).

10. As described in more detail in Exhibit A and the pre-filed direct testimony of FPL witness Francisco Prieto submitted contemporaneously with this Petition, the Duval-Raven Project is needed in December 2018 to: (a) serve the increasing load and customer base in the North Region, which includes all or portions of Brevard, Volusia, Flagler, St. Johns, Putnam, Bradford, Union, Columbia, Baker, and Duval counties, and in particular the area west of the existing Bradford and Baldwin Substations and east of the planned Raven Substation ("Service Area"); (b) increase the capacity of the existing 230 kV transmission network between the Duval, Baldwin, and Bradford Substations and relieve the loading on the existing 115 kV transmission network between the Baldwin, Bradford, and Columbia Substations in a reliable manner consistent with the reliability standards and criteria established by the North American Electric Reliability Corporation ("NERC"); and (c) provide another electrical feed from the Duval Substation in Duval County to the Lake City area in Columbia County largely adjacent to an existing 115 kV Right-of-Way ("ROW") path, thereby reducing the impact of a loss of the existing transmission facilities on a common ROW.

11. In order to enable FPL and the Commission to comply with the notice requirements of Section 403.537(1)(a), Florida Statutes (2015) and Rule 25-22.075, Florida Administrative Code, FPL previously filed a Notice of Intent to File Petition for Transmission Line Need Determination on December 11, 2015. The Commission has set the final hearing for this docket for February 24, 2016. FPL has published 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, FPL respectfully requests that the Commission:

A. Hold a hearing on this Petition in accordance with Section 403.537, Florida Statutes (2015), Chapter 120, Florida Statutes (2015), and applicable rules of the Commission;

B. Determine that there is a need for the Duval-Raven Project, with the starting point at FPL's existing Duval Substation in Duval County and the ending point at FPL's planned Raven Substation in Columbia County, taking into account the need for electric system reliability and integrity and the need for abundant, low-cost electrical energy to assure the economic well-being of the residents of this state; and

C. Enter a final order determining such need for the Duval-Raven Project.

Respectfully submitted,

By: *s/ William P. Cox*_______

William P. Cox
Senior Attorney
Florida Bar No. 0093531
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5662
(561) 691-7135 (fax)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was furnished by Electronic Mail to the following on the 11th day of January 2016:

Leslie Ames, Esq.
Lee Eng Tan, Esq.
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
lames@psc.state.fl.us
ltan@psc.state.fl.us

By: *s/ William P. Cox*________
William P. Cox, Esq.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150263-EI

FLORIDA POWER AND LIGHT COMPANY

JANUARY 11, 2016

IN RE: PETITION FOR DETERMINATION OF NEED FOR

DUVAL-RAVEN 230 KV TRANSMISSION LINE

IN BAKER, COLUMBIA, DUVAL, AND NASSAU COUNTIES, BY

FLORIDA POWER & LIGHT COMPANY

EXHIBIT A TO THE PETITION

The Duval-Raven Project

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Executive Summary

This Petition provides the background information concerning the Duval-Raven 230 kV Project ("DRP"), as well as the need for and benefits resulting from the DRP. The DRP maximizes system reliability, increases power transfer capability, and meets local area load requirements by serving proposed future distribution substations east of Interstate-75, south of Interstate-10 and west of the existing 230 kV transmission in Baker, Columbia, and Union Counties while minimizing cost to customers. The DRP will primarily consist of the construction of approximately 38.5 miles (subject to final certification under the Florida Transmission Line Siting Act or "TLSA") of a single circuit 230 kV transmission line in Baker, Columbia, Duval, and Nassau Counties. The need for the DRP is based on the following considerations:

- The need to provide additional transmission reinforcement to the existing 115 kV and 230 kV transmission network between Columbia, Bradford, and Baldwin substations in a reliable manner consistent with reliability standards and criteria established by the North American Electric Reliability Council ("NERC"), at the direction of the Federal Energy Regulatory Commission ("FERC"), and adopted by the Florida Reliability Coordinating Council ("FRCC").

- The need to serve the increasing load and customer base in the area east of Columbia and west of Baldwin and Bradford Substations.

- The opportunity, subject to final corridor siting certification under the TLSA, to efficiently and effectively integrate and serve existing and future new distribution substations that are needed to serve projected load growth within Baker, Bradford, Columbia, and Union Counties.

Over the past five years (2010-2014), the load in FPL's North Region, an area that includes all or portions of Brevard, Volusia, Flagler, St. Johns, Putnam, Bradford, Union, Columbia, Baker, and Duval Counties and the specific Project Service Area has grown by a Compound Annual Average Growth Rate ("CAAGR") of 1.3%. FPL is forecasting the North Region to continue to grow at CAAGR of 1.8% over the next five years (2015-2019). Transmission assessment studies conducted by FPL during 2014 and 2015 have identified regional transmission system limitations in Baker, Bradford, Columbia, and Union Counties. These studies show that by 2018, the existing 115 kV transmission network between Baldwin, Bradford, and Columbia Substations will not have sufficient capacity to provide reliable service to potential future distribution substations.

A new transmission line sited west from FPL's existing Duval Substation in Duval County to FPL's planned Raven Substation in Columbia County would be the most reliable, cost effective means to serve the projected load growth within Baker, Bradford, Columbia, and Union Counties.

A study of transmission improvements for this area evaluated various alternatives which resulted in the selection of the DRP as the most cost-effective and efficient means to both reinforce the existing 230 kV and 115 kV networks and provide electrical service to existing and future load areas and substations within the Baldwin-Columbia-Bradford transmission facilities.

In summary, the DRP presents the best alternative for satisfying the need for a reliable and cost-effective supply of power to FPL's existing and future customers within Baker, Bradford, Columbia, and Union Counties.

I. Description of FPL Electrical Facilities

In order to provide an overview of FPL's existing electrical transmission system, a map of FPL's high voltage transmission network indicating the general location of generating plants, major substations, and transmission lines is shown in Attachment 1. As shown on Attachment 1, the majority of the load in the northern portion of FPL's North Region is presently served by five north-south 230 kV circuits and two 500 kV circuits.

A listing of the history and forecast of FPL's peak demand is provided in Schedules 3.1 and 3.2 of Florida Power and Light Company's Ten Year Power Plant Site Plan (2015-2024) submitted on April 1, 2015, to the Florida Public Service Commission (the "Commission"), incorporated herein as Attachments 2 and 3.

The DRP will address the increasing forecasted demand and enhance reliability in the Baker, Bradford, Columbia, and Union Counties area and supply electric service to existing and future new distribution substations required along with the appropriate transmission and substation facilities southeast of Columbia substation, just west of Price substation in the existing 115 kV transmission network. The DRP best meets the needs of the Project Service Area, as described more fully in the following section.

II. The Duval-Raven Project

The DRP will consist of a new 230 kV transmission line extending from FPL's existing Duval Substation in Duval County to FPL's proposed Raven Substation (scheduled to be in service by December 2018) in Columbia County to provide needed reliability and power transfer capability by providing a third 230 kV transmission line injection to reinforce the existing 115 kV transmission network. The new transmission line is estimated to be approximately 38.5 miles in length (subject to final certification under the TLSA) and will connect FPL's Duval Substation to FPL's future Raven Substation. The line will be constructed with a single pole design primarily on existing and on limited new right-of-way ("ROW"), and will have a design and voltage of 230 kV. In fact, 96% of the new transmission line will be located within an existing easement where there is an existing 115 kV transmission line. The entire DRP will serve existing and future distribution substations in the Baker, Bradford, Columbia, and Union Counties Area and provide additional capability on the existing 230 kV transmission network.

FPL's selection of the project as the most cost-effective and efficient means to: (a) increase the capacity of the existing 230 kV transmission network between Duval, Baldwin, and Bradford Substations; (b) relieve potential overloads on the existing 115 kV system; (c) serve the projected customer load increase in the area; (d) maintain reliable service to FPL's customers; and (e) provide operational flexibility.

The DRP will also allow FPL to maintain and improve reliability to all FPL and Clay Electric Cooperative, Inc. ("CEC") customers within the Project Service Area consistent with NERC Reliability Standards. The proposed in-service date for the Project is December 2018.

Attachment 4 is a map showing the DRP along with the existing electrical facilities in the area. The line route and future substation site are conceptual and for illustrative purposes only.

A summary of the major project components is outlined below. Construction costs include design, engineering, ROW preparation, and land acquisition, in nominal or year-of-installation dollars.

Duval-Raven Project Construction Costs	**Estimated Cost in MM**
Estimated Transmission Line Costs (Duval Raven 230 kV line)	52.1
Loop Columbia to Macedonia 115 kV line	.9
Loop Bradford to Columbia 115 kV line	.9
Raven Substation: New substation	14.6
Duval Substation: New Line Terminal	2.5
Estimated Total Project Cost	**71 (79.9 CPVRR)**

III. Transmission Planning Criteria and Process

Planning for the FPL transmission system employs practices and criteria that are consistent with the Reliability Standards established by the NERC, at the direction of FERC and adopted by the FRCC. The applicable NERC Reliability Standards are included as Attachment 5. The NERC Reliability Standards specify transmission system operating scenarios that should be evaluated, and the levels of system performance that should be attained. FPL's transmission planning process is designed to ensure compliance with the NERC Reliability Standards, and involves three major steps: (1) the preparation of system models, (2) the assessment of the transmission system, and (3) the development and evaluation of alternatives. A more detailed discussion of these steps is provided in Attachment 6.

IV. Discussion of Need and Benefits

The need for DRP is based on the following considerations:

- The need to provide additional transmission reinforcement to the existing 115 kV and 230 kV transmission networks between Duval and Raven Substations in a reliable manner consistent with NERC Reliability Standards.
- The need to serve the increasing load and customer base in the Project Service Area.
- The need for another 230 kV injection, thereby reducing the impact of a loss of one of the existing 230 kV transmission sources.

New potential load development has been identified in the existing 115 kV transmission network between the Columbia, Baldwin, and Bradford Substations which will require new electrical service in the future. Additionally, the load served by the existing 115 kV transmission network has grown to the point where reinforcement of the network's capability is required to maintain adequate and reliable electric service. The DRP fulfills both the requirement to serve the new load in the Project Service Area as well as the requirement to reinforce the existing 230 kV network. A detailed description of these requirements follows.

A. Maintain System Reliability

The need for the DRP is based largely on the need to improve transmission reliability and power transfer capability by providing a new 230 kV injection from the existing Duval Substation to the proposed Raven Substation and looping the existing Columbia-Macedonia and Bradford-Columbia 115 kV transmission lines into the proposed Raven Substation (see Attachment 4). In addition, the DRP will considerably improve the voltage support in the area and efficiently and effectively integrate and serve new FPL and CEC distribution substations that are needed to serve the growing area in the future.

B. Serve Additional Load

In addition to reinforcing the existing 230 kV transmission network between Bradford, Columbia, and Baldwin substations, the DRP can facilitate transmission service for future substations serving loads east of I-75 and south of I-10. Regional load projections are developed as part of FPL's Distribution Planning Process. Attachment 7 contains a brief description of FPL's Distribution Planning Criteria and Process. There are no future substations and loads currently proposed in the project service area.

Load Flow Results Without the DRP

Page A.1 of Appendix A provides a "Load Flow Diagram Key" to assist in interpreting the load flow maps contained in Appendices A and B. Page A.2 shows a load flow output diagram of the 2018 winter peak load condition without the DRP in-service. The diagram represents what is called the base case scenario or normal condition (*i.e.*, no contingencies) for the year 2018/19 winter peak load. The diagram shows that all facilities are operating within normal equipment ratings (*i.e.*, no overloads or low voltages).

In accordance with NERC Reliability Standards TPL-003-0 - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-001-4 – Transmission System Planning Performance Requirements, Table 1 (Steady State & Stability Performance Planning Events) Categories P1 through P6, effective January 1, 2016), FPL must have a valid assessment and corrective plan to ensure that reliable systems are developed to meet specified performance requirements.

Page A.3 shows the power flows without the DRP in 2018 assuming the loss of the [redacted] and [redacted] line sections of the [redacted] and [redacted]% of its [redacted] amp thermal rating (see Attachment 8). This would potentially require interruption of service to approximately [redacted] customers in 2018 to reduce loading on this line to acceptable levels.

Page A.4 shows the flows without the DRP in 2018 assuming the loss of the [redacted] and [redacted] line sections of the [redacted] and [redacted] lines. This would potentially require interruption of service to approximately [redacted] customers in 2018 to reduce loading on this line to acceptable levels.

In addition, Pages A.5 through A.13 show overloads ranging from 121% to a high of 164% (See Attachment 8) of the thermal SOL[1] has MVA facility rating or voltages below 0.95 per unit caused by any of the following contingencies:

[redacted]	(Page A.5)
	(Page A.6)
	(Page A.7)
	(Page A.8)
	(Page A.9)
	(Page A.10)
	(Page A.11)
	(Page A.12)
	(Page A.13)

In order to mitigate the overloads and low voltages shown on Pages A.5 through A.13, it would potentially be necessary to interrupt the service of approximately [redacted] to up to [redacted] customers (approximately [redacted] to [redacted] people) depending on the specific outage.

<u>Load Flow Results – With the DRP</u>

Page A.14 is a loadflow output diagram showing 2018 winter peak conditions <u>with</u> the DRP in-service. The construction of the DRP provides a new 230 kV injection to

[1] SOL (System Operating Limits): The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria

reinforce the existing 115 kV network between Baldwin, Columbia, and Bradford Substations.

Page A.15 shows that with the DRP in-service, the loss of the [redacted] and [redacted] line sections does not result in the overloading of any transmission facility and an adequate voltage profile is maintained. This is due to the reinforcement of the existing transmission network provided by the DRP.

Page A.16 shows that with the DRP in service, the loss of the [redacted] and [redacted] line sections does not result in the overloading of any transmission facility and an adequate voltage profile is maintained. Again, this is due to the transmission network reinforcement provided by the DRP.

Pages A.17 through A.25 show that with the DRP in service, the same or similar contingencies shown on Pages A.5 through A.13 (See Attachment 8) will not cause overloads or low voltage conditions at any of the transmission facilities in the Project Service Area.

C. Project Benefits

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

- Maintains reliability by providing an independent 230 kV injection to the existing 115 kV network.
- Serves existing and future new load east of I-75, south of I-10 and west of the existing 230 kV transmission in Baker, Union and Columbia Counties.

- Increases reliability of the Project Service Area by providing an additional transmission injection to flow from the Duval Substation to a third location, the proposed Raven Substation.
- Reduces transmission losses by approximately 6 MW (during peak load).
- Improves significantly the required voltage support in the area.
- Meeting the Project Service Area's long term growth requirements for at least the next 10 years.

V. Discussion of Project Alternatives

In order to meet the additional load requirements and maintain a reliable electric system for the Project Service Area, the following alternatives were considered:

A. Reinforce the existing transmission network and serve the existing and future load with additional transmission facilities closer to the existing and/or future substations.

B. Relieve the existing transmission network and serve the existing and future load by locating generation within the Project Service Area.

C. Serve the existing and future load by expanding existing substations.

A discussion of these alternatives follows:

<u>Transmission Alternatives</u>

In order to reinforce the existing transmission network and to serve the load in the Project Service Area beyond December 2018 in a reliable and effective manner consistent with NERC Reliability Standards, three transmission alternatives were investigated. The factors used to evaluate the performance of the alternatives include reliability, cost, feasibility, and compatibility with long range plans. Those alternatives are discussed and assessed below. Attachment 9 includes a matrix comparing each of the transmission alternatives.

<u>Transmission Alternative I</u>

This alternative consists of performing ampacity upgrades and re-conductorings of approximately 47 miles of existing 115 kV transmission line sections between Baldwin, Bradford, and Columbia Substations, in addition to the installation of capacitor banks for voltage support in the Project Service Area.

Page B.1 is a loadflow map representing this alternative. The estimated capital cost of this alternative is $101.0M (95.1 CPVRR).

This alternative was rejected for the following reasons:

1. Some of the re-conductorings would require extended clearances that could potentially impact reliability in the area.
2. This alternative does not provide for future transmission network flexibility, nor does it improve reliability in the Project Service Area because it only reinforces the existing 115 kV network.
3. In the long term, a transmission solution (such as the proposed DRP) will still be required to reinforce the 115 kV network in order to serve future load growth in the area (by 2024) even if this alternative was in place.

Transmission Alternative II

This alternative consists of building a new double circuit 230 kV transmission line approximately 20 miles long from FPL's Columbia Substation on new ROW to looping-in-and-out from the existing corridor of the Duke Energy Florida, Inc.'s ("DEF") Suwannee River Plant-Ft. White North 230 kV transmission line into the existing Columbia Substation.

This alternative was rejected for the following reasons:

1. The Columbia Substation property is completely full and located in a residential area with no possibility for site expansion on existing property.
2. The alternative requires a new ROW acquisition for portions of the looping in-and-out of the 230 kV lines into Columbia County and Lake City.
3. The benefits of the alternative would depend on third party future generation plans.
4. The alternative introduces third party impacts on existing facilities that will require upgrades.

Transmission Alternative III

This alternative consists of building a new 230 kV transmission line approximately 25 miles long from FPL's Columbia Substation on new ROW to DEF's Ft. White North Substation.

This alternative was rejected for the following reasons:

1. Columbia Substation property is completely full and located in a residential area with no possibility for site expansion on existing property.
2. The alternative requires a new ROW acquisition for the proposed 230 kV line into Columbia County and Lake City.
3. The benefits of the alternative would depend on third party future generation plans.
4. The alternative introduces third party impacts on existing facilities that will require upgrades.
5. The alternative does not provide the same reliability performance as the DRP.

Attachment 9 shows the decision-making analysis which summarizes the points of comparison of the DRP and Transmission Alternative I, decribed above. The points of comparison are cost, reliability, ROW diversity, system expandability, operational flexibility, and construction difficulty.

Generation Alternatives

Generation alternatives such as siting a new generator in the Project Service Area were not considered viable for the following reasons:

- Siting and constructing new generation within the Project Service Area along with the additional transmission facilities to interconnect and integrate would go above and beyond what is presently required by the proposed project at a significant increase in cost.
- The need to provide transmission service to future proposed substations is not solved by adding generation in the Project Service Area.

For these reasons, a generation alternative was not considered further.

Distribution Alternatives

Distribution alternatives such as expanding existing substations were not considered viable because expansion of existing distribution substations will not address the primary need for the DRP (*i.e.*, provide an additional 230 kV injection to the existing 115 kV transmission network in the Project Service Area). Accordingly, a distribution alternative was not considered further.

VI. Adverse Consequences of Not Constructing the Duval-Raven Project

The purpose and need for the DRP is to serve the existing and projected load growth west of the existing 230 kV network in the Project Service Area and maintain a reliable cost effective supply of power to the loads served by the existing transmission network in a manner that complies with NERC Reliability Standards. If the DRP is not built by December 2018, then sufficient transmission capacity would not be available to serve the existing and future customers in the Project Service Area and the level of reliability would be below the level delivered to other FPL customers. The inability to serve additional loads could lead to the implementation of rolling outages to prevent system degradation.

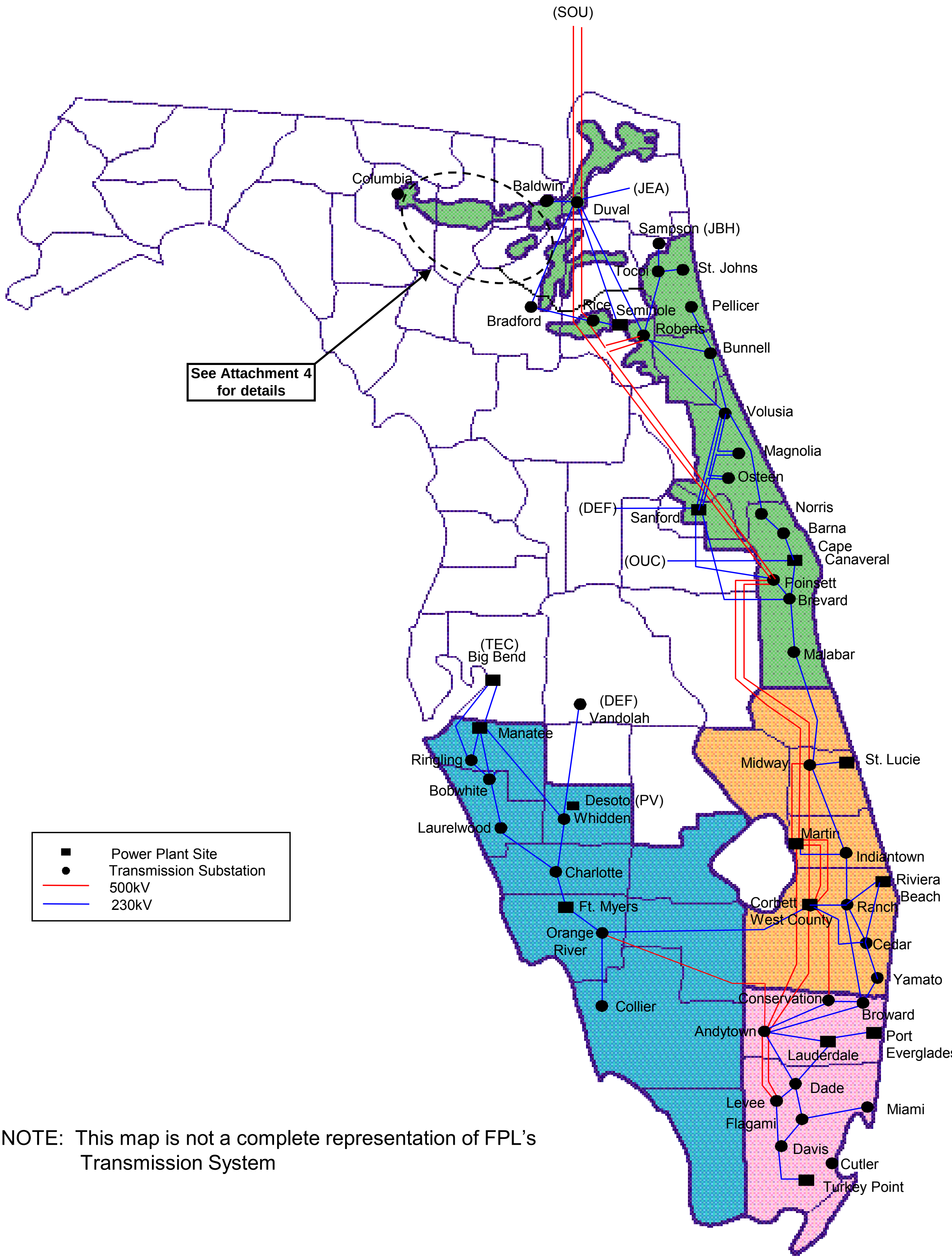
Practically speaking, however, if the DRP is delayed, or if the Commission denies the Petition, FPL would be forced to initiate implementation of Alternative I as discussed in section V in order to serve the area load with an acceptable level of reliability. The result would be that FPL would be required to address its customers' needs with a less reliable, more costly alternative than the DRP, and one that is not in the best long-term interest of FPL's customers when compared to the DRP.

VII. Conclusion

The DRP is needed by December 2018 to maintain reliable, cost-effective power supply within the Project Service Area and to better serve existing and future distribution substations. The alternatives to the DRP are more costly, do not provide for the future expansion of the transmission system in the Project Service Area, and do not provide the reliability benefits of an additional 230 kV injection. The Commission, therefore, should grant FPL's Petition for a Determination of Need for the Duval-Raven Project and determine that the cost and reliability benefits of the Project would preserve and enhance electric system reliability and integrity in the area.

ATTACHMENT 1

FPL Substation and Transmission System Configuration



NOTE: This map is not a complete representation of FPL's Transmission System

ATTACHMENT 2

Schedule 3.1
History of Summer Peak Demand (MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1,042	760	706	19,334
2009	22,351	249	22,102	0	981	1,097	811	732	20,558
2010	22,256	419	21,837	0	990	1,181	815	758	20,451
2011	21,619	427	21,192	0	1,000	1,281	821	781	19,798
2012	21,440	431	21,009	0	1,013	1,351	833	810	19,594
2013	21,576	396	21,180	0	1,025	1,394	833	827	19,718
2014	22,935	955	21,980	0	1,010	1,444	843	840	21,082

Historical Values (2005 - 2014):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2014 values which are through August.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2015	23,286	1,231	22,054	0	1,020	46	862	25	21,334
2016	23,778	1,240	22,538	0	1,030	60	873	37	21,778
2017	24,252	1,186	23,066	0	1,040	71	885	50	22,206
2018	24,648	1,145	23,502	0	1,051	82	897	63	22,555
2019	25,045	1,149	23,896	0	1,061	94	909	77	22,904
2020	25,369	1,150	24,219	0	1,071	106	920	91	23,181
2021	25,497	953	24,544	0	1,082	118	932	106	23,260
2022	25,833	957	24,875	0	1,092	131	944	121	23,545
2023	26,286	965	25,321	0	1,102	144	956	136	23,948
2024	26,771	972	25,798	0	1,113	157	968	152	24,381

Projected Values (2015 - 2024):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

ATTACHMENT 3

Schedule 3.2
History of Winter Peak Demand (MW)

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	895	687	721	291	22,730
2011	21,126	383	20,743	0	903	717	723	303	19,501
2012	17,934	382	17,552	0	856	755	722	314	16,356
2013	15,931	348	15,583	0	843	781	567	326	14,521
2014	17,500	890	16,610	0	768	805	590	337	16,142

Historical Values (2005 - 2014):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand. For year 2011, the actual peaked occurred in December of 2010.

Col. (5) - Col. (9) for 2005 through 2014 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1) January of Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management*	(7) Residential Conservation	(8) C/I Load Management*	(9) C/I Conservation	(10) Net Firm Demand
2015	21,136	1,195	19,941		841	12	593	5	19,684
2016	21,369	1,206	20,163		850	24	598	11	19,886
2017	21,485	1,151	20,334		858	28	603	20	19,976
2018	21,598	1,114	20,484		867	31	609	30	20,061
2019	21,792	1,125	20,667		875	35	614	40	20,227
2020	21,965	1,133	20,833		883	40	620	50	20,372
2021	22,096	1,141	20,956		892	44	625	61	20,475
2022	22,026	948	21,078		900	49	631	72	20,374
2023	22,202	956	21,246		909	53	636	83	20,520
2024	22,408	965	21,443		917	59	642	95	20,695

Projected Values (2015 - 2024):

Col. (2) - Col. (4) represent FPL's forecasted peak and does not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include MW values of load management from Lee County and FKEC.

Attachment 4 is Confidential in Its Entirety

ATTACHMENT 5

The Transmission Planning Criteria

Table 1 of TPL-001-4 NERC Reliability Standard divides Transmission Planning into eight categories, i.e., Categories P0 through P7 (see page 2 of this Attachment 5). FPL utilizes these Categories for its transmission planning criteria. Category P0 addresses normal system conditions with all facilities in service. Categories P1 and P2 addresses system conditions following a single contingency. Categories P3 through P7 address system conditions following multiple contingencies. Finally, Steady State & Stability Performance addresses system conditions following an extreme event where multiple facilities are removed from service.

The need for transmission system upgrades is most frequently based on potential overload conditions associated with Categories P1 and P2 contingencies (single contingency). Generally, Steady State & Stability Performance contingency analysis is used to identify potential situations of cascading interruptions and/or instability.

The planned transmission system with expected loads and transfers must be stable and within applicable ratings for all Categories P0 through P7 contingency scenarios.

The effect of Steady State & Stability Performance contingencies on the system is also evaluated. The design of new transmission connections should take into account and minimize, to the extend practical, the adverse consequences of Stability Performance contingencies. Lower probability Stability Performance contingencies, when they occur in combination with forecasted demand levels and firm interchange transactions, must not result in uncontrolled, cascading interruptions. While controlled interruptions of load and/or opening of transmission circuits may be needed, the system should be within its emergency limits and capable of rapid restoration after operation of automatic controls.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

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
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay [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.
      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.

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] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. 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.
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. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

ATTACHMENT 6

The Transmission Planning Process

The transmission planning process described in Diagram 1 (as well as in the FPL Open Access Transmission Tariff - Attachment K) consists of five major steps: (1) the preparation of system models, (2) the assessment of the transmission system performance to comply with NERC Reliability Standards, (3) the development and evaluation of transmission expansion alternatives, (4) the selection and approval of the preferred alternatives, and (5) the incorporation of FPL's expansion plan into the FRCC Regional Planning Process. These different steps are described below.

STEP 1: Preparation of System Models

To prepare system models, regional load profiles must be developed for the current year and for representative years of the ten-year planning horizon (2016 through 2025). These profiles incorporate the latest available substation load forecasts. The Distribution Planning groups in each region are requested to provide Transmission Planning with historical and projected substation loads, including future distribution substations, for incorporation into the Transmission Planning models. Each year the load forecasts are benchmarked against real-time historical station peak loads for validation of the forecasts and to make adjustments to future forecasts.

Once the load profiles have been developed, they are used as input to the loadflow, fault analysis and stability models, for simulation of the performance of the transmission system. Other major inputs into these programs are the generation expansion plan, generation dispatch and the base transmission system representation including expected line and equipment performance data. The generation expansion plan modeled assumes expected dispatch profiles, typical maintenance profiles at off-peak load levels, and other power schedules (e.g. firm interchange, etc.). Additionally, firm long-term transmission service obligations are incorporated into the models. The base transmission system representation incorporates existing and planned (budgeted) facilities. Appropriate operating criteria including thermal limits, voltage limits, generator reactive limits, and transformer taps are observed in developing the models. All major utilities to which FPL is interconnected are also represented in the models.

STEP 2: Assessing the Transmission System for Compliance

Planning for the FPL transmission system follows practices and criteria that are consistent and comply with the NERC Transmission Planning Reliability Standards. Standard TPL-001-4 describes scenarios to be tested and the required levels of system performance. In general, the system will remain stable and both thermal and voltage limits will be within applicable facility ratings for each of these categories:

<u>Category P0</u> - Represents System performance with no contingencies and all facilities in service.

<u>Category P1</u> - Represents System performance with single contingency events.

<u>Category P2</u> - Represents System performance with single contingency events (fault plus loss of two or more elements).

<u>Category P3</u> - Represents System performance under multiple contingencies (loss of generator unit).

<u>Category P4</u> - Represents System performance under multiple contingencies (fault plus stuck breaker).

<u>Category P5</u> - Represents System performance under multiple contingencies (fault plus relay failure to operate).

<u>Category P6</u> - Represents System performance under multiple contingencies (loss of one element followed by system adjustments).

<u>Category P7</u> - Represents System performance under multiple contingencies (common structure)

Table 1 of TPL-001-4 illustrates in more detail the specific NERC Reliability Standards mentioned above.

Using the system models developed in Step 1 and in accordance with NERC Reliability Standard TPL001-4, contingencies are simulated using loadflow and stability programs modeling snapshots of different system conditions. These contingencies consist of: (1) single events such as the loss of one transmission line section, autotransformer, or a generation unit, (2) single events with certain facilities unavailable (i.e. generators), and (3) credible multiple contingencies such as the loss of all transmission lines in a common transmission corridor. The latter have a lower probability of occurrence but can result in more severe consequences.

The need for transmission system upgrades is most frequently based on potential overload 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 meet initial thresholds that are consistent with the NERC Reliability Standards in terms of system performance, resulting conditions, and severity. 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.

The transmission system in Florida is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only to the North. Additionally, the major load center in Florida is in the most southern part of Florida, containing almost one half of the forecasted load. Because of its unique characteristics, Florida has a higher exposure to voltage and system stability issues such as system separation and under-frequency load shedding, than other parts of the country. Additional criteria have been developed to deal with Florida specific reliability problems. These practices are followed for internal improvements to the FPL transmission system as well as new interconnections to the FPL transmission system and are shown in FPL's Facility Interconnection Requirements document (posted at :)

https://www.oatioasis.com/FPL/FPLdocs/November_2015_REVISED_FIR_11122015.pdf

STEP 3: Development and Evaluation of Alternatives

During the screening evaluation process, areas that do not initially meet the thresholds consistent with NERC Reliability Standards identified in Step 2 are assessed for mitigation alternatives. First, switching techniques and other operational procedures are tested. If satisfactory operational procedures are not readily available, alternatives for transmission system reinforcements are developed with input from Engineering. The alternatives are assessed using steady-state load-flow and dynamic stability analyses to identify the viability of the mitigation alternatives. Cost estimates for the viable alternatives are also obtained from Engineering. These alternatives are further evaluated taking into account pertinent factors such as reliability, electrical performance, cost, construction difficulties, and flexibility to respond to changing future conditions. The results are then vetted through a "Tollgate Process" involving, Corporate Real-Estate, External Affairs, Distribution Planning, Construction, Engineering, and other FPL departments as necessary. This process is intended to identify and evaluate major milestones, or "Tollgates", and assign ownership that will ensure the most effective solution for project completion. Finally, during this step, previously budgeted projects are reviewed for need, timing, and electrical configuration. If necessary, revisions to the previously budgeted projects are addressed.

STEP 4: Selection and Approval

After careful evaluation of all alternative transmission system projects, and with the input provided in the Tollgate Process, a recommended transmission expansion plan is provided to management for budgeting and approval. Once approval is obtained, Power Delivery is requested to budget the projects to meet the required in-service dates.

STEP 5: FRCC Regional Transmission Planning Process[1]

After the projects are approved they are sent to the FRCC for incorporation into the Annual Transmission Planning Process portion of the FRCC's Regional Transmission Planning Process also shown in Diagram 1. This process facilitates coordinated planning by all transmission providers, owners and stakeholders within the FRCC Region. The FRCC is one of the North American Electric Reliability Corporation ("NERC") Regional Reliability Organizations, with responsibility for ensuring and enhancing the reliability and adequacy of bulk electricity supply in Florida.

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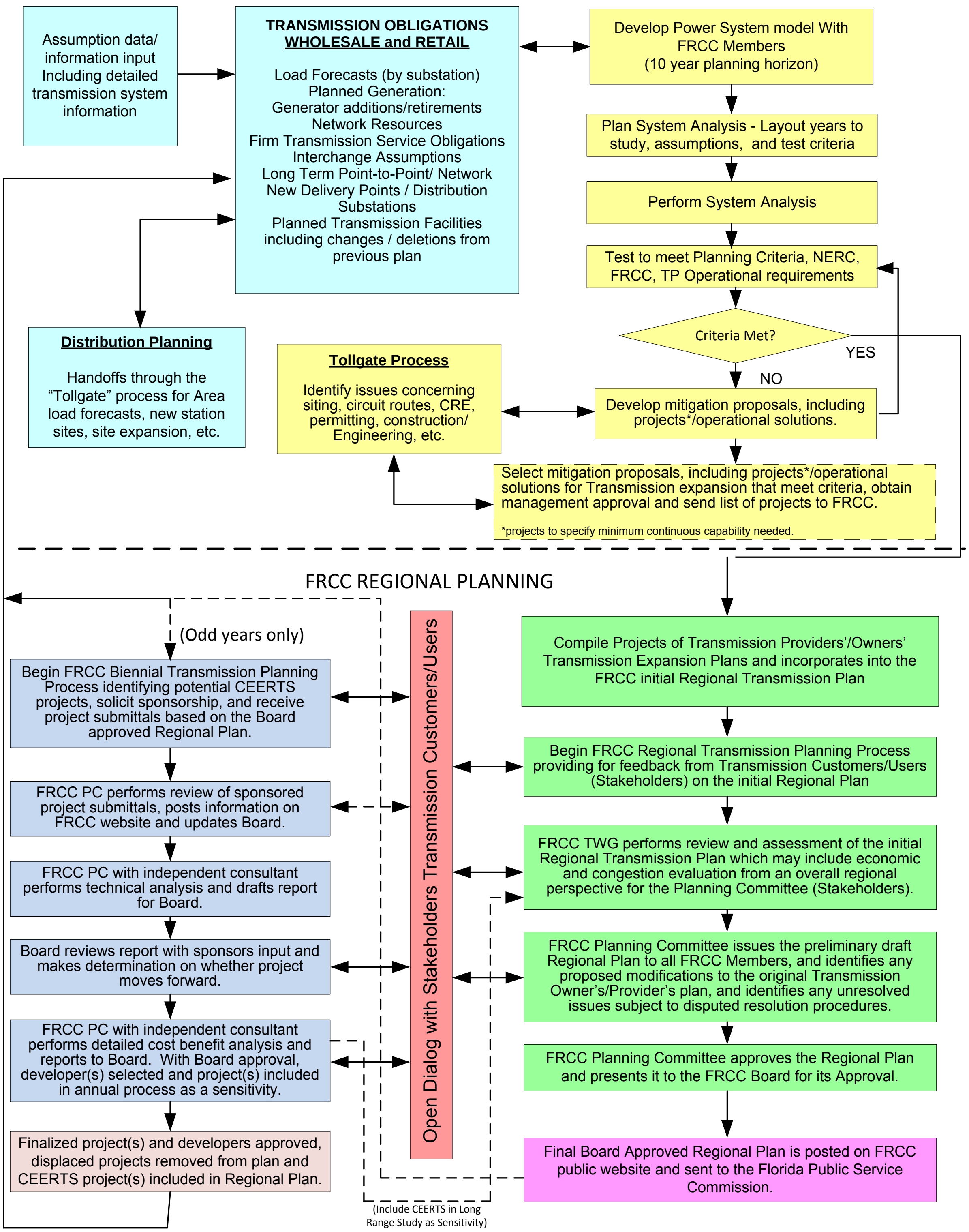
[1] As a result of the Federal Energy Regulatory Commission's (FERC) Order 1000, the FRCC's Regional Transmission Planning Process ("RTPP") has been modified and expanded to include two simultaneous processes. The Annual Transmission Planning Process ("ATPP"), which coordinates the FPL Power Delivery Expansion Plan with the expansion plans of all of the FRCC member utilities, and the Biennial Transmission Planning Process ("BTPP"), which is separate and distinct from the ATPP, in that its purpose is to analyze previously approved transmission plans and develop more Cost Effective or Efficient Regional Transmission Solutions ("CEERTS") which could ultimately impact the FPL Power Delivery Expansion Plan. The complete RTPP is a public document and is posted at: https://www.frcc.com/Planning/Shared%20Documents/Regional%20Transmission%20Planning%20Process/FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf

Diagram 1

Transmission Planning Process Overview



ATTACHMENT 7

The Distribution Planning Criteria and Process

The objective of the planning criteria is to provide substation and feeder capacity at an optimal cost while maintaining the acceptable reliability and operating flexibility. This will be done by improving the utilization of existing and future feeder and substation capacity, and without imposing undue burden on distribution facilities to backstand substation transformer capacity for extended periods of time.

As part of the annual Planning/Budgeting process, Distribution Planning reviews existing feeder peak loads and forecasted new loads based on ongoing construction projects. Their primary interest is to identify the need for new distribution projects (new feeders, feeder ties, upgrades, etc.) to ensure system reliability is maintained. In addition to these efforts, the process also facilitates the forecasting of future distribution substation power transformer loads and associated potential overloads by rolling up feeder loads to the transformer level. Other relevant information used during the process includes reviewing the number of customers outages following a transformer outage, capability to transfer load via field switching of the distribution system, number of switching operations and time to transfer load, as well as critical customers potentially affected. These criteria are used to help risk-rank and fund potential projects

The Distribution Planning process can be divided into 5 major steps: (1) validating feeder and substation peak loads, (2) preparing models for analysis, (3) running analysis-Load Flow (feeder & transformer), auto throw-over, contingency (feeder & transformer), Automatic Feeder Switch, Protection and model feeder criteria, (4) evaluating and provide solutions for exceptions identified, and (5) ranking project solutions and develop budget estimates for the plan.

Attachment 8 is Confidential in Its Entirety

Attachment 9

Transmission Alternative Decision Making Analysis

DECISION STATEMENT		Provide adequate and reliable service in an economical manner to the Baker, Bradford, Columbia, and Union Counties area											
OBJECTIVES		ALTERNATIVES: All in service dates are based on the Regional Load forecast											
		I/S YEAR		Selected Project	I/S YEAR		Alternative I	I/S YEAR		Alternative II	I/S YEAR		Alternative III
		2018		Construct a new Duval-Raven 230kV transmission line with a minimum rating of 1905 amps (759MVA), a 230/115kV breaker station "Raven" with line terminals and a 230/115kV, 560MVA autotransformer. Upgrades two 115kV transmission line sections: Raven-Tustenuggee Tap and Raven-Columbia.	2018		Perform line upgrades on eight 115kV transmission line sections: Columbia Tap-Tustenuggee Tap, Tustenuggee Tap-Wiremill Tap, Sanderson Tap-Macedonia, Macedonia-McClenny, MacClenny-Baldwin, Baldwin-Maxville Tap, New River Tap2-Starke and Price-Columbia. Install 2-25MVAr capacitor banks at Price substation.	2018		Construct a new double circuit 230kV transmission line with a minimum rating of 1905 amps (759MVA) to loop-in-and-out the existing Suwannee River Plant-Ft. White 230kV line into Columbia substation, add 230kV line terminals and a 230/115kV, 560MVA autotransformer.	2018		Construct a new Ft. White-Columbia 230kV transmission line with a minimum rating of 1905 amps (759MVA), into Columbia substation, add 230kV line terminals and a 230/115kV, 560MVA autotransformer.
					2024		Provide a 230kV Injection in the Area						
REQUIREMENTS		Yes	No		Yes	No	Information	Yes	No	Information	Yes	No	Information
Alternative must provide for reliable service to area customers		X		Provides additional 230kV injection to the area in addition to providing overload relief and voltage support on the transmission network under several contingencies.	X		Provides overload relief on the transmission network under several contingencies.	X		Provides additional 230kV feed to the area in addition to providing overload relief on the transmission network under several contingencies.	X		Provides 230kV injection to the area in addition to providing overload relief on the transmission network under several contingencies.
Alternative Plan is feasible to construct		X			X				X	Not feasible. There is no possibility for site expansion on existing property at Columbia Substation		X	Not feasible. There is no possibility for site expansion on existing property at Columbia Substation
DESIRES	VL	Score	VL*S	Information	Score	VL*S	Information	Score	VL*S	Information	Score	VL*S	Information
Minimize Price (Present value of revenue requirements)	10.0	10.0	100	$77,900,000 CPVRR	7.4	74	$90,500,000 CPVRR			Not feasible			Not feasible
Maximize reliability of service to customers	9.2	10.0	92	Provides greater reliability to a larger service area.	8.0	74	Provides short term relief for approx. 6 years.						
Maximize compatibility with Long range plans. Flexibility	6.1	10.0	61	Best-Satisfies current and future load growth in the area.	5.0	31	Contributes little to the long range expansion of the area.						
Provides operational flexibility	5.3	10.0	53	provides maximum operational flexibility	5.0	27	Provides minimum operational flexibility						
Minimize construction difficulties	4.9	9.0	44	New transmission line. Requires minimum line clearences on three existing lines.	5.0	25	Potential delays -clearances difficult to obtain. Requires several line clearences.						
TOTAL VALUE SCORE			350	** PREFERED ALTERNATIVE **		229				Not Feasible.			Not Feasible.

APPENDIX A

Load Flow Diagrams- With and Without Project

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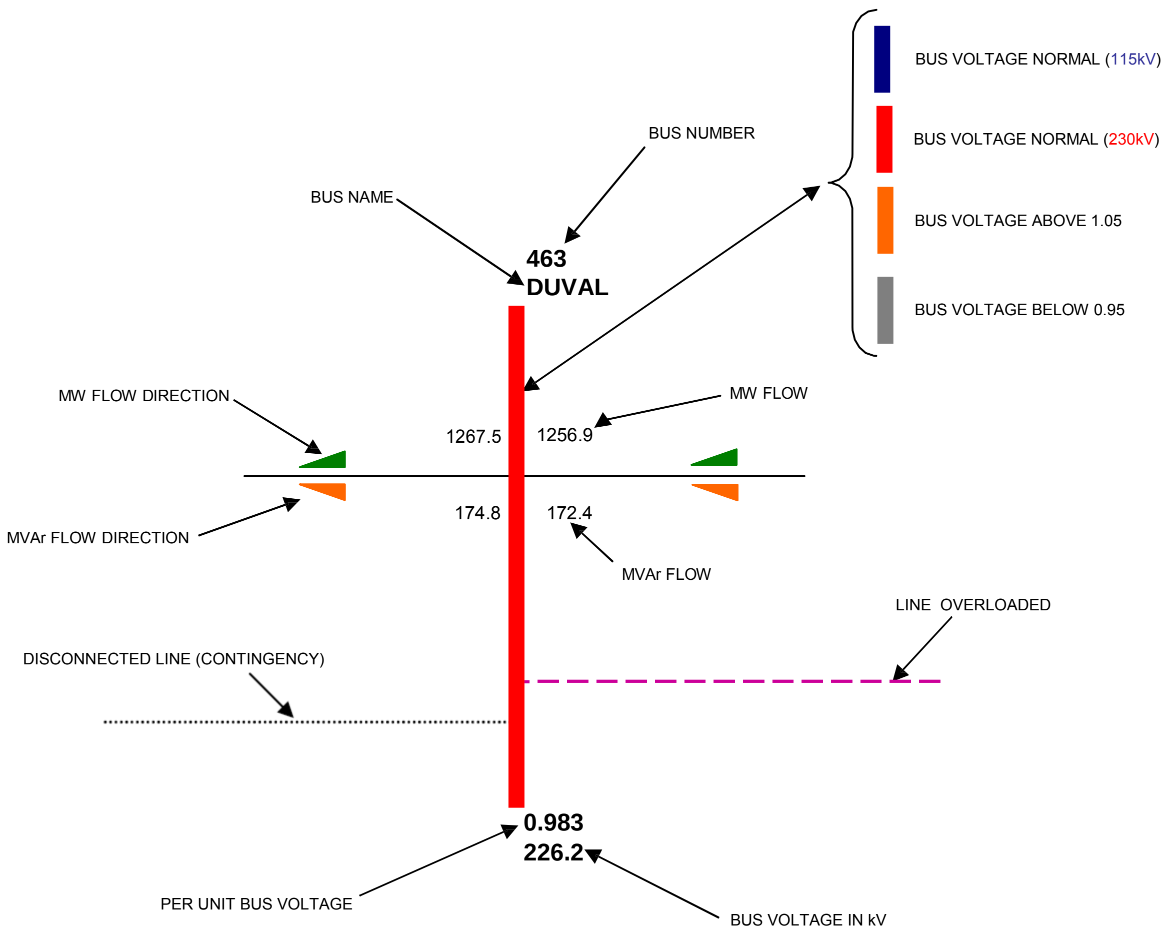
Load Flow Maps with the Project

Load Flow Diagram Key



Pages A2 through A25 are Confidential in Their Entirety

APPENDIX B

Load Flow Diagrams- Alternatives

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED FOR

DUVAL-RAVEN 230 KV TRANSMISSION LINE IN

BAKER, COLUMBIA, DUVAL, AND NASSAU COUNTIES

DIRECT TESTIMONY OF FRANCISCO PRIETO

DOCKET NO. 150263-EI

JANUARY 11, 2016

Q. Please state your name and business address

A. My name is Francisco Prieto. My business address is 4200 W. Flagler Street, Miami, Florida 33134.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Senior Manager, System Planning.

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

A. My responsibilities include the direct supervision of engineers in the development and evaluation of transmission expansion plans utilizing load flow analysis. I have held this position and performed these responsibilities since April of 2012.

Q. Please describe your educational background and professional experience.

A. I graduated from the Florida International University with a Bachelor of Science degree in Electrical Engineering in May of 1990. From 2007 through

April 2012, I served as Senior Manager of System Operations. I was responsible for supervising FPL Transmission System Operation personnel to ensure the safe, reliable operation of the FPL Bulk Power System in compliance with the North American Reliability Corporation ("NERC") Reliability Standards. My primary duties and responsibilities included the operation and coordination of the FPL Generation, Transmission, and Substation system in order to provide reliable service to FPL's customers in an efficient manner. I also ensure on-going personnel training needs are met on all processes and procedures necessary to maintain situational awareness during normal and emergency conditions.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring Exhibits FP-1 through FP-3, which are attached to my direct testimony.

Exhibit FP-1	Map of Transmission and Generation
Exhibit FP-2	Duval-Raven Expected Construction Schedule
Exhibit FP-3	List of Contingencies

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and support FPL's request for a determination of need for the Duval-Raven Transmission Project ("DRP"). Specifically, my testimony presents the following information in support of the DRP:

- General overview of the FPL transmission system;

- A general description of the DRP including the design and operating voltage of the proposed transmission line, the starting and ending points of the line, the approximate cost of the DRP, and the projected in service date;
- The specific conditions, contingencies, and factors which demonstrate the need for the DRP, including a discussion of FPL's transmission planning process and the reliability benefits of the DRP;
- The major alternatives to the DRP that were evaluated and rejected by FPL in favor of the DRP; and
- The adverse consequences to FPL's electric system and customers if the DRP is delayed or denied.

Q. Please summarize your testimony.

A. The DRP 230 kV transmission line is the best and most cost-effective alternative available to meet an FPL transmission need in December 2018, taking into account the demand for electricity, the need to meet NERC Reliability Standards for electric system reliability and integrity, and the need for abundant, low-cost electrical energy to assure the economic well-being of the residents of this state. FPL has examined all reasonable alternatives for this need and determined that the DRP will provide its customers with sufficient reliability at the lowest cost while maintaining operational flexibility for FPL's system. Without this addition to the FPL transmission system in December 2018, the economic well-being of Floridians would be at risk due to needed electric service to meet projected new load in the affected region and heightened exposure to potential system reliability and integrity issues.

OVERVIEW OF FPL'S TRANSMISSION SYSTEM

Q. Please describe FPL's transmission system.

A. FPL is part of the nation's Eastern Interconnection transmission network. It has multiple points of interconnection with other utilities that enable power to be exchanged among utilities. The FPL transmission system is comprised of approximately 6,888 circuit miles of transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 596 substations.

The FPL transmission system is designed to integrate all of FPL's generation resources to serve FPL's retail customers and to meet FPL's firm long-term transmission service obligations in a reliable and cost effective manner. It is planned and designed consistent with Reliability Standards and criteria established by the NERC, at the direction of the Federal Energy Regulatory Commission ("FERC"), and adopted by the Florida Reliability Coordinating Council ("FRCC").

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

A. FPL's existing load characteristics consist primarily of residential and commercial load with limited industrial load. FPL's summer peak demand in 2015 was 22,959 MW and the winter peak demand in 2015 was 19,718 MW, serving approximately 4.8 million customers. An overview of FPL's existing electrical transmission network indicating the general location of generating plants, substations, and transmission lines is shown in Exhibit FP-1.

DESCRIPTION OF THE DRP

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

A. The proposed line will connect from FPL's existing Duval Substation in Duval County to FPL's planned new Raven Substation in Columbia County (by December 2018) and to several substations in the area via upgraded existing 115 kV transmission lines in Columbia County to address the anticipated transmission system limitations.

As shown in Exhibit FP-3, FPL's studies indicate transmission limitations on the existing 115 kV transmission network west of Baldwin Substation and west of Bradford Substation. The new Duval-Raven 230 kV transmission line will efficiently and effectively integrate and serve existing FPL and Clay Electric Cooperative, Inc. distribution substations and any future substations needed to serve the growing load in this area. In addition, the DRP would mitigate potential overloads and low voltage conditions under contingency events.

Q. What is FPL's timetable for licensing, design, and construction of DRP?

A. For an indicative schedule of licensing, designs, and construction, please see Exhibit FP-2.

Q. What is FPL's estimated capital cost of the DRP?

A. The estimated capital cost of the DRP is $71 million in 2018 dollars.

FPL PLANNING PROCESS

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

A. FPL's transmission system planning is governed by a series of NERC Reliability Standards mandated by FERC and enforced by the FRCC. The DRP is intended to meet NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirement). The applicable NERC Reliability Standard is included as Attachment 5 to the Petition. Under TPL-001-4, FPL is required, on annual basis, to complete a planning assessment of its portion of the Bulk Electric System ("BES") that addresses near-term and long-term planning horizons for steady state, short circuit, and stability conditions. TPL-001-4 specifies transmission system operating scenarios that should be evaluated, and the levels of system performance that should be attained. FPL's transmission planning process is designed to ensure compliance with the NERC and FRCC Planning Standards and involves three major steps: (1) the preparation of system models, (2) the assessment of the transmission system, and (3) the development and evaluation of alternatives.

Q. What studies did FPL perform to determine the need for the DRP?

A. Transmission assessment studies conducted by FPL in 2014 and 2015 have identified regional transmission system limitations in Baker, Bradford, Columbia, and Union Counties. These studies indicate that by December 2018, the existing 115 kV transmission network between Baldwin, Bradford, and Columbia Substations will not have sufficient capacity to provide reliable service to existing and proposed substation loads.

NEED FOR THE PROJECT

Q. Please explain the need for the DRP.

A. The need for transmission system upgrades is based on potential overload conditions associated with single contingency events, which occur when a single element such as a generator, transmission circuit, or transformer is disconnected from the system. If FPL does not add new transmission capability in the Project Service Area by December 2018, FPL forecasts potential overloads ranging from 9 to 14 percent of the thermal line ratings and low voltage conditions under 3 separate single contingency events.

Q. Please explain the benefits of the DRP.

A. The proposed DRP would assure the economic well-being of the residents of the state by providing low-cost electric service to projected new load in the region and improving the region's electric system reliability by minimizing the region's exposure to single contingency events. The proposed DRP will also reduce on-peak transmission losses by approximately 6.3 MW. While the final cost of the DRP is subject to the final route and length of the line and other conditions that could be imposed through the Transmission Line Siting Act process, I believe the DRP is the most cost-effective alternative to meet our customer's needs.

Q. Please describe the contingencies that require the addition of the DRP.

A. Based on the Florida Power And Light Company's 2015 Ten Year Power Plant Site Plan load forecast, there are approximately 118 potential System Operating Limits ("SOL") violations under multiple double contingencies (N-

1-1) in the Baldwin-Columbia-Bradford 115 kV area in December 2018 [see Exhibit FP-3]. If the DRP is completed by December 2018, the number of potential SOL violations will be eliminated.

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

A. The projected in-service date is December 2018.

Q. Would construction of the DRP provide for further load growth as well as resolve these contingencies?

A. Yes. An analysis of transmission alternatives resulted in FPL's selection of the the DRP as the most cost-effective and efficient means to: (a) increase the capacity of the existing 230 kV transmission network between FPL's Duval, Baldwin, and Bradford Substations and relieve the loading on the existing 115 kV system in a reliable manner consistent with NERC Reliability Standards; (b) serve the projected customer load increase in the area West of the existing Bradford and Baldwin Substations and east of the planned Raven Substation; and (c) provide another electrical feed from the Duval Substation in Duval County to the Lake City area in Columbia County.

Q. Are there other reliability and strategic benefits associated with the DRP?

A. The DRP will increase reliability by providing a new 230 kV injection from the existing Duval Substation to the proposed Raven Substation and looping the existing Columbia-Macedonia and Bradford-Columbia 115 kV transmission lines into the proposed Raven Substation. Further, the DRP serves a strategic purpose by supplying potential future industrial, commercial, and residential load south and east of Lake City and west of the existing 230 kV transmission network from the northern portion of Duval to the southern portion of Bradford County while maximizing system reliability and minimizing cost to customers.

DISCUSSION OF ALTERNATIVES

Q. Did FPL consider alternatives to the DRP?

A. Yes.

Q. What factors were employed to evaluate the alternatives?

A. The factors used to evaluate the performance of the alternatives included reliability, cost, construction feasibility, operational flexibility, right of way ("ROW") diversity, and future transmission system expandability.

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

A. FPL evaluated three alternatives to the proposed DRP. Alternative I consists of ampacity upgrades of several line sections, some of these sections requiring reconductoring, in the 115 kV network between Baldwin, Bradford, and Columbia Substations. Installation of capacitor banks for voltage support would also be required. This alternative was deemed not to be practicable because its implementation does not provide a long term solution in the outer years of the planning horizon because it only reinforces the 115 kV network and, long term, does not alleviate the need for future transmission reinforcement in the area.

Alternative II consists of building a new 230 kV transmission line approximately 20 miles from the Columbia Substation on a new ROW to loop in and out of the existing Duke Energy Florida, Inc. ("DEF") Suwannee River Plant-Ft. White North 230 kV transmission line into the existing Columbia Substation. This alternative was not considered a practicable option because of the need to potentially acquire approximately 20 miles of new ROW, a portion of which is located in residential areas in unincorporated Columbia County and Lake City, coupled with limited space at the FPL Columbia Substation property, also located in a residential area. An expansion of this substation would be required, and the existing substation property is not large enough to accommodate this expansion. Therefore, additional property would have to be purchased for the expansion.

Alternative III consists of building a new 230 kV transmission line from the existing DEF Ft. White Substation to the existing Columbia Substation. This alternative was not considered a practicable and timely option because of the need to acquire new ROW, some portion of which is in residential areas in unincorporated Columbia County and Lake City.

Q. Please describe why generation alternatives were not considered viable.

A. Generation alternatives were not considered viable given the absence of a preferred generation site in the area of the DRP. Preferred sites represent those locations where FPL has conducted significant reviews, and has either taken action, or is currently committed to take action, to site new generation capacity. FPL will continue to evaluate whether there are any sites in the area of the DRP that have potential as a site for future generation. However, no final plans have been made in this regard.

Q. Please describe why distribution alternatives were not considered viable.

A. Most of the distribution system in Columbia, Union, and Baker Counties is dependent on the existing 115 kV transmission network between Baldwin, Bradford, and Columbia Substations, and by December 2018, the distribution system will not have sufficient capacity to provide reliable service to existing and proposed substations, hence a new transmission line is required.

ADVERSE CONSEQUENCES OF DELAY OR DENIAL OF THE DRP

Q. Would there be adverse consequences to FPL's customers in the DRP Service Area if the DRP is not timely approved?

A. Yes. If FPL does not add new transmission capability in the DRP Service Area by December 2018, potential overloads are forecasted ranging from 9 to 14 percent of the thermal line ratings and low voltage conditions under three separate single contingency events, thus causing a violation of the NERC Reliability Standards.

Q. What would be the impact if certification of the DRP was denied?

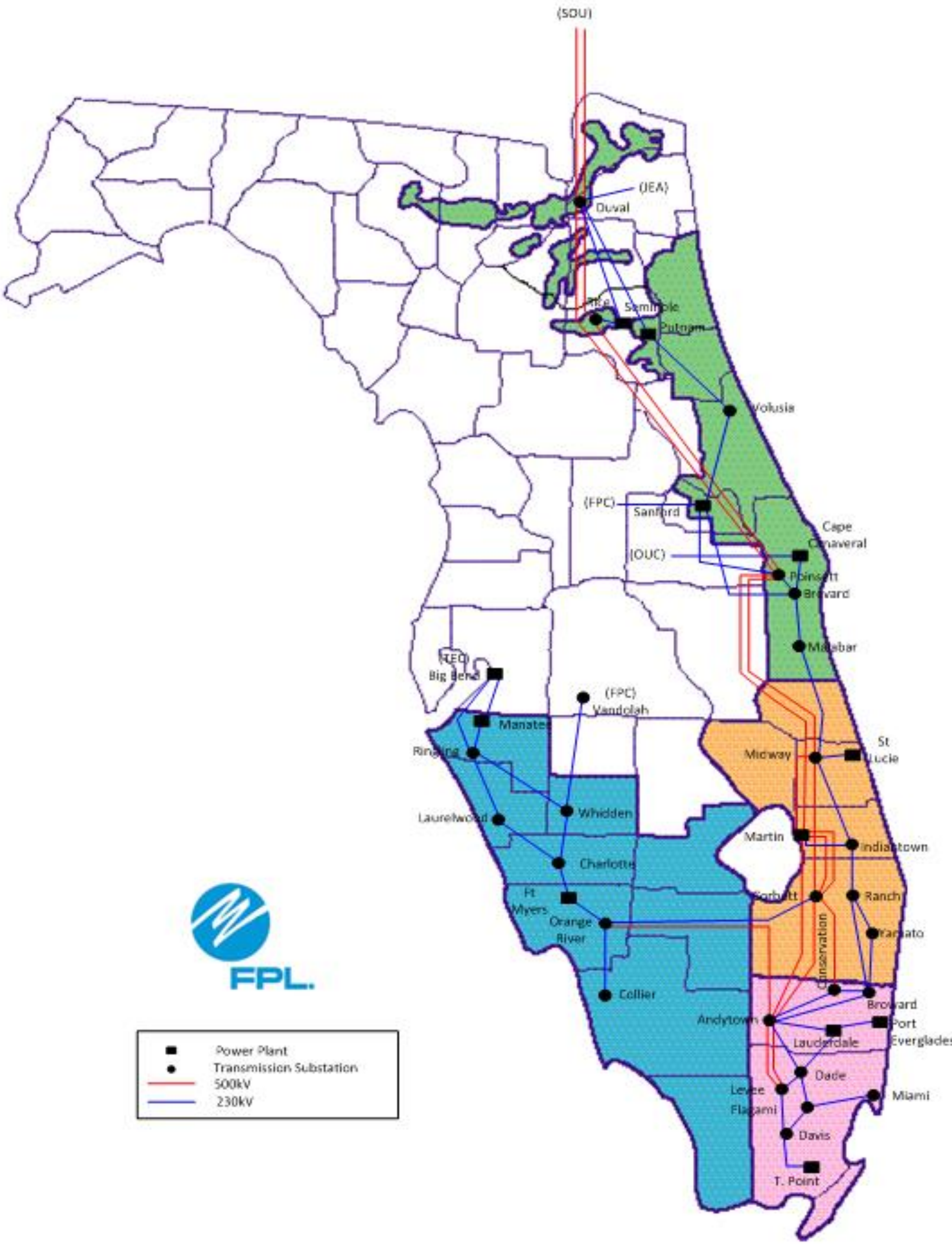
A. As discussed above, the economic well-being of the residents of the state would be at risk due to the lack of needed electric service to meet projected new load in the region, and exposure to potential system reliability and integrity issues would be heightened.

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

A. Yes. For all the reasons described above, the Commission should determine that there is a need for the Duval-Raven 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 testimony?

A. Yes.


(SOU)
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Duval
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Big Bend
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Vandolah
Manatee
Midway
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Lucie
Whidden
Laurelwood
Martin
Charlotte
Ft
Myers
Ranch
Orange
River
Conservation
Collier
Broward
Andytown
Port
Everglades
Lauderdale
Dade
Levee
Miami
Flagami
Davis
T. Point
FPL.
Power Plant
Transmission Substation
500kV
230kV

Duval-Raven Expected Construction Schedule

Milestone	Begin	End
TLSA and Need Determination	Apr, 2015	Dec, 2016
Transmission Line and ROW Design & Material Orders	Jan, 2016	Aug, 2016
Substation Design & Material Orders	Jan, 2016	Aug, 2016
Permitting (Station & Line)	Dec, 2016	Sep, 2017
Raven Site Preparation	Jan, 2017	Jun, 2017
ROW Acquisition	Jan, 2017	Dec, 2017
Transmission Line ROW Prep	Oct, 2017	Sep, 2018
Substation Construction (Duval, Raven)	Jun, 2017	Aug, 2018
Transmission Line Construction	Nov, 2017	Dec, 2018
In-Service/Commissioning	-	Dec, 2018

Exhibit FP-3 is Confidential in Its Entirety