NEPR

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COMMONWEALTH OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: REVIEW OF T&D'S OPERATORS SYSTEM OPERATION PRINCIPLES	**CASE NO. NEPR-MI-2021-0001** **SUBJECT:** Responses to April 6th Resolution and Order and to Requests for Information on System Operation Principles.

MOTION IN COMPLIANCE WITH RESOLUTION AND ORDER OF APRIL 6, 2021 AND SUBMITTING RESPONSES TO REQUESTS FOR INFORMATION

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COME now **LUMA Energy, LLC** ("ManagementCo"), and **LUMA Energy ServCo, LLC** ("ServCo"), (jointly referred to as "LUMA"), and respectfully state and request the following:

1. On February 25, 2021, LUMA filed before this Honorable Puerto Rico Energy Bureau ("Energy Bureau") a Petition for Approval of LUMA's System Operation Principles ("SOP Petition"), pursuant to LUMA's obligations under Section 4.1 (h) of the Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement dated as of June 22, 2020, executed by and among LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public-Private Partnerships Authority ("P3 Authority") ("OMA").

2. On April 6, 2021, this honorable Energy Bureau issued a Resolution and Order on "Completeness of LUMA's System Operation Principles Filing." ("April 6th Order"). This honorable Energy Bureau stated that additional discussion on "key matters, supporting data, analysis, and assessments [is] necessary for the Energy Bureau[] [to conduct an] adequate evaluation [of the System Operation Principles]." *See* April 6th Order at page 2.

3. In the April 6th Order this Energy Bureau directed LUMA to, within ten days that are set to expire on April 16, 2021, provide information and responses to the requests for information that are included in Attachment A ("Requests for Information") and modify the SOP Petition accordingly. *Id.*[1]

4. With this Motion, LUMA is submitting its responses to the eleven Requests for Information that are included in Attachment A to the April 6th Order. *See* Exhibit 1 ("Responses"). The Responses include the following documents and attachments that will be filed for the record using the Bureau's electronic platform and/or sent via email as explained in the table below:

System Operation Principles Request Number	Documents Filed with the Energy Bureau	Format of Documents and mode of submission
01	Response	Pdf document filed using the Bureau's electronic filing system
02	Response	Redacted pdf document filed using the Bureau's electronic filing system and unredacted confidential version to be sent via email
03	Response	Pdf document filed using the Bureau's electronic filing system
04	Response	Pdf document filed using the Bureau's electronic filing system
05	Response	Pdf document filed using the Bureau's electronic filing system
06	Response	Pdf document filed using the Bureau's electronic filing system
07	Response	Pdf document filed using the Bureau's electronic filing system
07	Attachment 1	Excel table, to be sent via email
08	Response	Pdf document filed using the Bureau's electronic filing system

[1] This Energy Bureau also directed that PREPA should provide LUMA any information or documents requested by LUMA to comply with the April 6th Order and afford assistance on clarifications that LUMA may require. *See* April 6th Order at page 2.

09	Response	Pdf document filed using the Bureau's electronic filing system
09	Attachment 1	Pdf document, submitted using the filing docket
10	Response	Pdf document filed using the Bureau's electronic filing system
10	Attachment 1	excel document, submitted via email (confidential)
11	Response	Pdf document filed using the Bureau's electronic filing system
11	Attachment 1	Redacted pdf document filed using the Bureau's electronic filing system and unredacted confidential version to be sent via email

5. Under separate cover, LUMA will be submitting a request to file some of the aforementioned attachments under seal of confidentiality.

6. It is respectfully submitted that with this Motion, LUMA does not require to modify the SOP Petition and is not submitting additional revisions to the System Operation Principles.

WHEREFORE, LUMA respectfully requests that the Bureau **take notice** of aforementioned, **accept** LUMA's Responses to the Requests for Information that are being submitted today, and **deem** that LUMA complied with the April 6th Order.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 15th day of April 2021.

I hereby certify that I filed this motion using the electronic filing system of this Energy Bureau and that I will send an electronic copy of this motion to the attorneys for PREPA, Joannely Marrero-Cruz, jmarrero@diazvaz.law; and Katiuska Bolaños-Lugo, kbolanos@diazvaz.law.

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NEPR-MI-2021-0001

System Operations Principles Response to April 6, 2021 RFI

List of Response Attachments

Response ID	Attachment Name	Description
RFI-LUMA-MI-21-0001-210406-PREB-007	Attachment 1*	Procedure Cross-Reference Matrix and Development Status Summary
RFI-LUMA-MI-21-0001-210406-PREB-009	Attachment 1	NERC Standard TPL-001-4
RFI-LUMA-MI-21-0001-210406-PREB-010	Attachment 1*	Transmission Substation Inspections Data
RFI-LUMA-MI-21-0001-210406-PREB-011	Attachment 1	Generation Plant Assessment

*Note: * Denotes attachments that have been provided in Microsoft Excel format.*

Request Naming Convention

Please note that LUMA proposes to use the following naming convention to categorize and reference any requests made in this process and future processes.

Example:

RFI-LUMA-MI-21-0001-210406-PREB-001

Request for Information	Recipient of Request	Compressed Docket Number	RFI Receipt Date	Initiator of Request	Request Number

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-001

Request:

Provide a detailed discussion, including the methodology to be used by LUMA for the development of load forecasts, including, but not limited to, (i) on a daily and day-ahead basis load forecast; and (ii) sub-hourly, hourly, daily, weekly, and monthly generation forecasts, particularly from wind and solar resources.

Response:

For a detailed discussion, including methodology for the development of load forecasts please refer to RFI-LUMA-MI-21-0001-210406-PREB-002.

Further details of operational load forecasting will be defined in the new load forecast procedure, which is a wave two procedure and discussed in RFI-LUMA-MI-21-0001-210406-PREB-007.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-002

Request:

Provide a detailed discussion on how LUMA will use and manage load forecasts in the Energy Management System ("EMS"). Describe LUMA's intended process for procuring a new EMS system, and the anticipated timeline for such a system to be installed and operational.

Response:

Soon after service commencement LUMA will be updating and improving the existing load forecast process. A stand-alone load forecast procedure will be developed for operations as a Phase II procedure (please refer to RFI-LUMA-MI-21-0001-210406-PREB-007 response) and will be completed by the end of calendar year 2021. This procedure may have some process improvements implemented but will largely reflect current practices.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Please find LUMA's working timeline as follows:

March 2021 – July 2021 – We will identify and document EMS business requirements. The requirements will be informed by LUMA's System Operations procedures (refer to RFI-LUMA-MI-21-0001-210406-PREB-007 response). As part of this there will be an outreach to peer utilities to identify current best practices and ongoing developments in system operations, especially with regard to managing high renewables penetration, preparing for severe weather and other disruptive events, and to operating an islanded system that cannot rely on interconnections. The business requirements will be consistent with the System Operation Principles.

July – October 2021 – Develop detailed EMS technical requirements to be used in a Request for Proposal (RFP). Develop IT and commercial / contractual requirements for the RFP and reach out to EMS suppliers to review available solutions and discuss any specific requirements, such as the potential need to operate minigrids during system disturbances.

October - December 2021 – Issue the RFP to EMS suppliers. LUMA can draw on internal subject matter experts with extensive experience in developing EMS requirements and managing procurements as well as actually building EMS from a former vendor role. As yet, a definitive schedule for "go live" of a new EMS has not been finalized. The existing EMS although near-obsolete, can be supported. The major risk to manage is a higher penetration rates of variable generation potentially overwhelming the existing EMS capability to manage a larger number of injection points. Our current estimate is that an EMS procurement and implementation process would take 36 months from commencement of the process to completion of installation of the new system.

[redacted]

LUMA anticipates being able to present a plan for the new CC soon after commencement in conjunction with the detailed plans for a new EMS.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-003

Request:

Provide a detailed discussion on how LUMA will use and manage load forecasts in performing Security Constrained Economic Dispatch ("SCED").

Response:

RFI-LUMA-MI-21-0001-210406-PREB-002 described steps LUMA will follow to improve overall load forecasting capability.

It is expected that a third-party load forecast software product will likely be acquired. LUMA will assess available products as part of its detailed assessment after commencement. Presuming a new load forecast tool is acquired, it would be used standalone until it could be integrated with the new EMS. It is typical for load forecast software to be supplied by third-party and not the EMS vendor, this solution will be viable for LUMA.

Load forecast is one of several critical tasks required for SCED to be reliable. The network model must be updated and validated and the state estimator reliably operational. The generation cost curve and other data must be updated. Ideally contingency analysis should be operational in order to include n-1 limits analysis although there are workarounds if this is not possible. Line ratings must also be validated. LUMA has teams engaged with the line rating validation and network model and will begin work on the state estimator soon after these are completed.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-004

Request:

Provide a detailed discussion of the mechanisms, procedures, tools, platforms and manuals to be used by LUMA to ensure compliance with the provisions of Act 17-2019, regarding the processing and handling of requests for interconnection to the PREPA grid, including the completion of interconnection studies and evaluations, when required.

Response:

LUMA is establishing a new distributed and utility scale generation interconnection agreement procedure, which will ensure compliance with the provisions of Act 17-2019 on large scale generation, and will include the following:

- Process and steps from initiating an interconnection application to sign an interconnection agreement,
- Definition of required interconnection studies; Screening/pre-application study phase, System Impact study phase, and Facilities Studies phase,
- Leveraging power system simulation models developed by consultants, such as those delivered by Sargent & Lundy, for performing future system impact studies.
- Determination of interconnection studies' schedules, interconnection fees and required deposits,
- Template for generic Interconnection Agreement form,
- Definition of the interconnection facilities, and outline required interconnecting facility data and information, and
- Definition of the process for maintaining an interconnection queue and assigning unique interconnection queue position for each interconnection application.

Another LUMA effort to support integration of distributed energy resources is development of streamlined interconnection processes and standards for the DERs currently covered under Regulation 8915, for efficient and agile processing of customer applications. Interconnection queue processing is normally based on first in – first out principles subject to hosting capacity and interconnection studies. To facilitate renewable integration, a streamlined interconnection process will be defined for timely processing of the volume of applications.

LUMA is in the process of conducting an end-to-end review of the interconnection process to identify and plan process improvements and to resolve the existing application backlog. The objective of this process review is to work collaboratively with the PREPA SMEs, incorporate any 3rd party advice (National Lab

Reports) and use industry best practices to identify a process that will complete the back log and handle ongoing applications in a timely manner. LUMA SMEs continue to evaluate the existing process by working with PREPA SMEs, reviewing the online portal for adequacy and reviewing application tracking data to identify process bottlenecks and current cycle times.

LUMA has already identified the following potential opportunities for improvement:

- **Centralize and Standardize**. The interconnection application process is currently conducted in regional offices, which are not centrally coordinated. Each office has differing levels of staff capacity available to process applications and each office administers the process in different ways. LUMA will centralize the application processing function, which will be standardized and coordinated through a dedicated team.
- **Resource Assistance**. LUMA will augment this team's capacity in the near term to help process the application backlog, train staff to implement streamlined application processes and in the long run will automate majority of manual process. The additional staff needed for the short-term mission to clear the backlog will be employed in processing applications received, which show a steeply ascending trend. Furthermore, the field inspection requirement for a portion of the DER interconnections represents another bottleneck and LUMA is developing an initiative to resolve this delay.
- **Online Platform**. The current application intake platform offers significant opportunity for improvement. LUMA is currently reviewing this platform to identify opportunities to reconfigure for more intuitive, stable and efficient application intake. Over time the system will be improved to provide more intuitive user interface with clear instructions and accessibility to application status information.
- **Screening Process**. LUMA will investigate opportunities to make the technical screening process more prescriptive to simplify the review process conducted by engineers and facilitate identifying DERs that require planning technical studies. This will eventually lead to automation of some application processing steps.
- **Hosting Capacity Analysis/Tools**. LUMA's ongoing hosting capacity analysis will enable the following outcomes:
    - Accelerate DER deployment by focusing development in areas with higher hosting capacity (and therefore lower cost to interconnect)
    - Facilitate more streamlined interconnection screening processes by replacing less accurate rules of thumb in interconnection screening processes
    - Proactively identify system upgrades needed to improve hosting capacity, which will help to reduce costs and barriers for future DER integration.
    - More effectively identify cases where planning technical studies are required and enable a more focused feasibility assessment
- **System Upgrades.** LUMA will propose a mechanism to manage system upgrades arising due to dispersed DERs connected under the expedited process as defined by Act 17-2019.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-005

Request:

Provide a detailed discussion on the safeguards and procedures to be implemented by LUMA to ensure non-discriminatory access to the Puerto Rico electric transmission and/or distribution system.

Response:

Refer to RFI-LUMA-MI-21-0001-210406-PREB-007 for LUMA's discussion of its system operation procedures, the specific procedure related to non-discriminatory access is Energy Dispatch, Scheduling and Merit Order. By having shift operators follow these procedures, LUMA will be implementing the measures to provide non-discriminatory access to the system.

After service commencement, LUMA will develop and begin tracking more system data, and by will be able to make more data available to PREB and/or stakeholders. This additional information will allow others to better understand how the system is dispatched.

Currently, PREPA does not measure or analyze the difference between what a non-constrained economic dispatch would look like compared to actual dispatch. With a more usable fact basis, LUMA can quantify the impact of security constraints by analyzing actual dispatch decisions and power output across all generators. Only after we gather this dispatch history can we have the empirical basis to review dispatch practices and assess where we can improve. We will then also be able to determine if procedure compliance or real-time decision-making in response to system stability issues needs to be improved to achieve more efficient dispatch.

During the course of developing this improved understanding of actual dispatch practices, we will also have the new data available to test if any dispatch decisions are influenced by asset ownership. The new EMS to be installed will also greatly enhance our dispatching and our ability to analyze large amounts of historical datasets. As discussed in the SOP, LUMA will be reporting on system operations activities. We recognize the importance of being able to provide more data and information on system dispatch to PREB and stakeholders. Greater access to data will help demonstrate that effectively there is non-discriminatory treatment.

As it pertains to interconnections, refer to LUMA-MI-21-0001-210406-PREB-004.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-006

Request:

Provide a copy of the Agreed Operating Procedures referenced in Schedule 1 to Annex I of the OMA and an explanation as to why the Agreed Operating Procedures were not included in the SOPs Plan.

Response:

LUMA established a new document called a Plant Level Agreement (PLA) which will cover all of the content described in Schedule 1 to Annex 1 related to Agreed Operating Procedures (AOP). LUMA has standardized the terminology, references, and hierarchy of documents in order to address identified issues, and to make the PLA a standard agreement that will be required of all existing and future generators. As described below, LUMA has not yet finalized these PLAs as they require discussions with generating plants once LUMA is operator, and as such they are not included in the SOP.

LUMA will create a procedure entitled "Creation of Plant Level Agreements" (called Plant-Level Agreements in SOP Appendix A.2) defining what the PLAs will contain and how they will be developed for all new generators interconnecting to the system which will be completed prior to commencement (refer to RFI-LUMA-MI-21-0001-210406-PREB-007). It is critically important to instill this discipline at the early stage of procedure development. PLAs for all interconnected generating plants today and in the future should be as similar as possible, and exceptions should be clearly noted to help ensure non-discriminatory dispatch. Each generator will work with LUMA to develop the PLA for their specific plant. Although they will be standardized, there will be several items that will be unique to each plant, such as names and phone numbers of contact personnel, role in emergencies, level of detail and frequency of interaction with the Control Center (CC). In this way, the CC will have a notebook of the PLA for each plant, and each plant manager will have a copy of that same agreement on their desk so when routine or emergency communications are required, all parties have a consistent and agreed understanding of the roles and responsibilities of each, which reduces the potential for problems.

Below is the detailed table of contents for the form of Plant Level Agreement that LUMA is developing.

Figure 1 – Draft Plant Level Agreements Table of Contents

PLANT LEVEL AGREEMENT

Table of Contents

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-007

Request:

LUMA discusses numerous areas where it intends to develop specific procedures in addition to the SOP. More specifically, LUMA states that it has identified (i) 12 critical operating procedures to be revised and re-written prior to commencement; (ii) 13 non-critical operating procedures to be revised and re-written within six months of commencement; (iii) and 4 operating procedures to be completed within 12 months after commencement of operations. For each of the specific procedures listed in Appendix A.2 of the SOP, submit the following:

a. A detailed discussion on how LUMA intends to operate the system in an improved manner while lacking the foregoing operating procedures, some of which LUMA itself identifies as critical; and

b. A detailed and aggressive completion timeline.

Response:

BACKGROUND TO THE PROCEDURE DEVELOPMENT TEAM

In September, as part of LUMA's gap assessment, it was identified that there are no written policies or procedures being used for the activities of the PREPA System Operations group. With input from the SOP Planning Team (that included PREPA subject matter experts) LUMA determined that:

1) System operating procedures should be developed based on the SOP submitted to PREB,
2) Work on the system operating procedures should begin promptly after submittal of the SOP to PREB, and
3) Creation of the full set of system operating procedures could not reasonably be completed before commencement.

As a result, LUMA and PREPA developed a Procedure Development Team (PDT) and prioritized and sequenced the creation of the system operating procedures listed in Appendix A into the following categories (as shown in Figure 2-1 on page 11 of the filed SOP):

- Phase I - Critical Operating Procedures
- Phase II - Non-Critical Operating Procedures
- Phase III - Process / Support Procedures

Phase I procedures were identified as needing to be completed prior to commencement and Phase II and Phase III procedures could be completed after commencement.

Following the submittal of the SOP to the PREB, LUMA and the PDT began work on writing the Phase I system operating procedures. LUMA is on track to complete Phase I procedures prior to commencement. Twelve procedures are included in Phase I – Critical Operating Procedures and are listed below:

- Plant Level Agreements
- Critical Loads
- Emergency Response Execution
- Generation & Transmission Demarcation and Metering
- Policy on Reserves
- Energy Dispatch, Scheduling, and Merit Order
- Black Start
- Public Reporting
- Contingency and System Operating Limits
- Balancing Frequency and Voltage
- Forced Outage Response
- Resource Adequacy Assessments

Phase II and Phase III procedures were scheduled to be completed 6- and 12-months post commencement, respectively.

a. Detailed discussion on how LUMA intends to operate the system in an improved manner while lacking the foregoing operating procedures, some of which LUMA itself identifies as critical

LUMA will have the 12 Phase I - Critical Operating Procedures in place at commencement and will implement those procedures upon commencement. In addition to the Phase I system operating procedures, LUMA is developing documentation prior to commencement of PREPA system operations current practice. This 'as-is' documentation enables business continuity while Phase I procedures are being implemented and while Phase II and Phase III system operation procedures are developed and subsequently implemented.

Development of 'as-is' documentation is progressing and has provided an opportunity to detail each step with the PREPA system operators, further understand how processes are currently performed, and identify opportunities for improvement. These 'as-is' documents, incorporating identified improvements where possible, will be relied on along with Phase I procedures to operate the system until such time that all three Phases of procedures can be implemented.

It is worth noting that the development of 'as-is' documentation and procedures has been done in close cooperation with PREPA system operations personnel. Almost all PREPA system operators have expressed the perspective that this will greatly improve effectiveness and consistency of control center processes, and that they have not had the time or resources to do this before. This process provides the overall structure to facilitate leveraging the current operators' experience in a constructive manner.

b. A detailed and aggressive completion timeline

Development of an entire set of operating procedures is a considerable undertaking. The procedure cross reference matrix in Figure 1 assists in the review process. This matrix is also provided within RFI-LUMA-MI-21-0001-210406-PREB-007 Attachment 1 in Microsoft Excel format. As can be seen in the matrix, most procedures are affected or related to at least 9-10 other procedures. These procedures are interrelated, and so each time a new procedure is complete, previously completed procedures are reviewed for consistency.

Figure 1 – Procedure Cross-Reference Matrix

Procedure Reference Matrix	Phase I	Load Forcasting	New Generation Interconnections	Resource Adequacy Assessments	Retirements	G & T Demarcatoin & Metering	Generator Capability	Black Start	Telemetry	Data/Cybersecurity	Root Cause & Lessons Learned	Public Reporting	Performance Reporting	Stakeholder Management	Policy on Reserves	Reducing Risk Exposure to Contingencies	Critical Loads	Load Shedding	Contingency and System Operating Limits	Energy Dispatch, Scheduling, and Merit Order	Transmission Operations	Plant Level Agreement	Balancing Frequency and Voltage	Demand Side Resources	Shift System Operator Training Requirements	Scheduling Planned T&G Outages	Forced Outage Response	Outage Execution & Closeout	Emergency Response Execution	Emergency Drills
New Generation Interconnections	II		x						x													x			x					
Resource Adequacy Assessments	I	x		x	x		x	x				x	x	x	x				x	x			x	x	x					
G & T Demarcation & Metering	I					x			x												x				x					
Generator Capability	II	x		x	x	x	x	x	x			x	x		x				x	x	x	x	x		x		x	x	x	x
Black Start	I	x		x	x		x	x	x			x	x		x				x	x	x	x			x				x	x
Public Reporting	I			x								x	x	x	x			x							x				x	x
Policy on Reserves	I	x		x	x		x	x							x	x			x	x		x	x		x	x	x			
Critical Loads	I																x	x							x				x	x
Contingency and System Operating Limits	I						x		x	x	x					x			x						x					
Energy Dispatch, Scheduling, and Merit Order	I	x					x	x	x						x		x		x	x		x	x		x	x	x	v	x	
Plant Level Agreement	I				x		x	x	x	x					x							x	x		x	x	x	x	x	
Balancing Frequency and Voltage	I						x																		x					
Forced Outage Response	I																					x			x		x	x	x	
Emergency Response Execution	I							x	x			x	x	x			x	x	x	x					x				x	x

Development of Phase I procedures is underway and progressing on schedule. As the LUMA team continues to progress the procedures and 'as-is' documentation, efficiency has been improving. As such, two of the Phase II procedures have been advanced and we currently anticipate will be completed prior to commencement. We now anticipate that all Phase II and Phase III procedures will be completed 6 months after commencement. Assuming a June 1, 2021 commencement date, all procedures are anticipated to be completed by the end of calendar year 2021. This is an acceleration of our original schedule, which had Phase III procedures scheduled for completion within 12 months of service commencement.

For a summary of the development status, please refer to Figure 2 below. This figure is also provided within RFI-LUMA-MI-21-0001-210406-PREB-007 Attachment 1 in Microsoft Excel format.

Figure 2 – Procedure Development Status

Procedure Development Team Status Tracking

As Of:	05-Apr-21

Procedure Summary — **Status Against Milestone Dates**

Phase	Section Grouping	Summary of Procedures		Interview Operator	"AS-IS" Complete	"AS-IS" Validated	Outline submitted to QRT	Coordinator Assessment	50% Edit	75% Text Complete	75% Edit	95% Text Complete	95% Edit	Final Review
I	Dispatch Operations	Plant Level Agreements	*forecast*	15-Mar	16-Mar	17-Mar	17-Mar	23-Mar	28-Mar	01-Apr	03-Apr	08-Apr	11-Apr	15-May
I		Plant Level Agreements	*actual*											
I	Contingency Planning	Critical Loads	*forecast*	12-Mar	13-Mar	14-Mar	14-Mar	20-Mar	25-Mar	29-Mar	31-Mar	05-Apr	08-Apr	15-May
I		Critical Loads	*actual*											
I	Emergency Response	Emergency Response Execution	*forecast*	09-Mar	10-Mar	11-Mar	11-Mar	17-Mar	22-Mar	26-Mar	28-Mar	02-Apr	05-Apr	15-May
I		Emergency Response Execution	*actual*											
I	Standards	G & T Demarcation and Metering	*forecast*	12-Apr	13-Apr	14-Apr	14-Apr	20-Apr	25-Apr	29-Apr	01-May	06-May	09-May	15-May
I		G & T Demarcation and Metering	*actual*											
I	Reserves	Policy on Reserves	*forecast*	08-Mar	09-Mar	10-Mar	10-Mar	16-Mar	21-Mar	25-Mar	27-Mar	01-Apr	04-Apr	15-May
I		Policy on Reserves	*actual*											
I	Dispatch Operations	Energy Dispatch, Scheduling, and Merit Order	*forecast*	20-Mar	21-Mar	22-Mar	22-Mar	28-Mar	02-Apr	06-Apr	08-Apr	13-Apr	16-Apr	15-May
I		Energy Dispatch, Scheduling, and Merit Order	*actual*											
I	Standards	Black Start	*forecast*	25-Mar	26-Mar	27-Mar	27-Mar	02-Apr	07-Apr	11-Apr	13-Apr	18-Apr	21-Apr	15-May
I		Black Start	*actual*											
I	Standards	Public Reporting	*forecast*	28-Mar	28-Mar	29-Mar	30-Mar	04-Apr	09-Apr	10-Apr	14-Apr	17-Apr	21-Apr	24-Apr
I		Public Reporting	*actual*											
I	Contingency Planning	Contingency and System Operating Limits	*forecast*	30-Mar	31-Mar	01-Apr	01-Apr	07-Apr	12-Apr	16-Apr	18-Apr	23-Apr	26-Apr	15-May
I		Contingency and System Operating Limits	*actual*											
I	Dispatch Operations	Balancing Frequency and Voltage	*forecast*	01-Apr	02-Apr	03-Apr	03-Apr	09-Apr	14-Apr	18-Apr	20-Apr	25-Apr	28-Apr	15-May
I		Balancing Frequency and Voltage	*actual*											
I	Outage Management	Forced Outage Response	*forecast*	21-Apr	22-Apr	23-Apr	23-Apr	29-Apr	04-May	08-May	10-May	15-May	18-May	15-May
I		Forced Outage Response	*actual*											
I	Planning	Resource Adequacy Assessments	*forecast*	20-Apr	21-Apr	22-Apr	22-Apr	28-Apr	03-May	07-May	09-May	14-May	17-May	15-May
I		Resource Adequacy Assessments	*actual*											

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-008

Request:

Describe how gaps identified in LUMA's review of PREPA system operations will affect the implementation of the SOPs Plan and related policies and procedures, and how LUMA believes it will affect implementation of Security Constrained Economic Dispatch, reliability management, and other principles and expectations for industry standard operations.

Response:

A number of gaps have been identified throughout the PREPA organization. Specific SRP projects have been identified to acquire the tools, training or hardware to address gaps and develop the capability to operate more effectively in the future. Specific SRP Projects related to System Operations and implementation of the SOP include:

- Critical Energy Management System Upgrades
- Critical Energy Management & Load Generation Balancing
- Control Center Construction & Refurbishment
- Operator Training
- Critical System Operation Strategy & Processes
- Supporting Shared Services for Generation
- Improvements to System Dispatch for Increased Reliability and Resiliency
- Resource Planning and Processes to Improve Resource Adequacy and Cost Tracking

Implementation of the SRP projects will provide the required tools and capabilities, but the implementation of the SOP and the timeline to realize the full benefits will be affected by broader thematic gaps that the question refers to. LUMA will need to actively manage these gaps and develop interim solutions ('as-is' documentation, process improvements, resource adequacy planning, procedural compliance, etc.) until SRP projects are implemented and instill the behavioral changes needed to implement the SOP. The most significant gaps that LUMA management will be focused on include:

- Adequate Resource Adequacy to meet load requirements.
- Situation awareness of full range of operating conditions, the potential for imminent system events, and ability to implement recognized mitigation measures.
- Behavioral changes that enforce procedural compliance and root cause analysis of events.
- Adequate communication capability and automation tools to be able to instantly respond to contingencies.
- Access to accurate cost and performance data to make real-time decisions and to properly understand the impact of past decisions and actions.

At the heart of LUMA's takeover activities to address these gaps are the development of written procedures that adequately describe all activities performed so that all parties are operating from a consistent set of common assumptions and responses. Implementation of Security Constrained Economic Dispatch and reliability management, and improvement of load forecasting will be realized when these procedure are followed. Adherence to these procedures represents a significant shift from the way PREPA currently operates. Instilling this behavioral change will require reinforcement and compliance will need to be monitored. Further, adequate training on the procedures will be required. After training and cultural reinforcement, comes the assessment to ensure they are being properly followed. This will include root cause analyses after each operating event including a check if procedural compliance was a factor in the event and random procedural compliance audits. Procedure compliance will be assessed on an annual basis.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-009

Request:

Submit the Transmission Planning Standards used for contingency planning.

Response:

For the Transmission Planning Standards used for contingency planning, please refer to the NERC Standard TPL-001-4 included in RFI-LUMA-MI-21-0001-210406-PREB-009 Attachment 1. This material is also available online at https://www.nerc.com/files/TPL-001-4.pdf and the above referenced attachment was obtained from the NERC website on April 14th, 2021.

While NERC standards are not required to be implemented in Puerto Rico, LUMA considers the NERC standards as useful guidelines and industry best practice for achieving system security, reliability and other goals in accordance with the System Operation Principles. LUMA will be taking a practical approach to implementing TPL-001-4 in Puerto Rico and anticipates it to be consistent with the applicable components of the standards within 24 months after service commencement.

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

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	Stability
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.	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 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

  b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
TPL-001-4	R1.	01/01/2015		06/30/2023
TPL-001-4	R2.		01/01/2016	06/30/2023
TPL-001-4	R3.		01/01/2016	06/30/2023
TPL-001-4	R4.		01/01/2016	06/30/2023
TPL-001-4	R5.		01/01/2016	06/30/2023
TPL-001-4	R6.		01/01/2016	06/30/2023
TPL-001-4	R7.	01/01/2015		06/30/2023
TPL-001-4	R8.		01/01/2016	06/30/2023
TPL-001-4	1.1.	01/01/2015		06/30/2023
TPL-001-4	1.1.1.	01/01/2015		06/30/2023
TPL-001-4	1.1.2.	01/01/2015		06/30/2023
TPL-001-4	1.1.3.	01/01/2015		06/30/2023
TPL-001-4	1.1.4.	01/01/2015		06/30/2023
TPL-001-4	1.1.5.	01/01/2015		06/30/2023
TPL-001-4	1.1.6.	01/01/2015		06/30/2023
TPL-001-4	2.1.		01/01/2016	06/30/2023
TPL-001-4	2.1.1.		01/01/2016	06/30/2023
TPL-001-4	2.1.2.		01/01/2016	06/30/2023
TPL-001-4	2.1.3.		01/01/2016	06/30/2023
TPL-001-4	2.1.4.		01/01/2016	06/30/2023
TPL-001-4	2.1.5.		01/01/2016	06/30/2023
TPL-001-4	2.2.		01/01/2016	06/30/2023
TPL-001-4	2.2.1.		01/01/2016	06/30/2023
TPL-001-4	2.3.		01/01/2016	06/30/2023
TPL-001-4	2.4.		01/01/2016	06/30/2023
TPL-001-4	2.4.1.		01/01/2016	06/30/2023
TPL-001-4	2.4.2.		01/01/2016	06/30/2023

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

United States

TPL-001-4	2.4.3.		01/01/2016	06/30/2023
TPL-001-4	2.5.		01/01/2016	06/30/2023
TPL-001-4	2.6.		01/01/2016	06/30/2023
TPL-001-4	2.6.1.		01/01/2016	06/30/2023
TPL-001-4	2.6.2.		01/01/2016	06/30/2023
TPL-001-4	2.7.		01/01/2016	06/30/2023
TPL-001-4	2.7.1		01/01/2016	06/30/2023
TPL-001-4	2.7.2.		01/01/2016	06/30/2023
TPL-001-4	2.7.3.		01/01/2016	06/30/2023
TPL-001-4	2.7.4.		01/01/2016	06/30/2023
TPL-001-4	2.8		01/01/2016	06/30/2023
TPL-001-4	2.8.1.		01/01/2016	06/30/2023
TPL-001-4	2.8.2.		01/01/2016	06/30/2023
TPL-001-4	3.1.		01/01/2016	06/30/2023
TPL-001-4	3.2.		01/01/2016	06/30/2023
TPL-001-4	3.3.		01/01/2016	06/30/2023
TPL-001-4	3.3.1.		01/01/2016	06/30/2023
TPL-001-4	3.3.2.		01/01/2016	06/30/2023
TPL-001-4	3.3.1.1.		01/01/2016	06/30/2023
TPL-001-4	3.3.1.2.		01/01/2016	06/30/2023
TPL-001-4	3.4.		01/01/2016	06/30/2023
TPL-001-4	3.4.1.		01/01/2016	06/30/2023
TPL-001-4	3.5.		01/01/2016	06/30/2023
TPL-001-4	4.1.		01/01/2016	06/30/2023
TPL-001-4	4.1.1.		01/01/2016	06/30/2023
TPL-001-4	4.1.2.		01/01/2016	06/30/2023
TPL-001-4	4.1.3.		01/01/2016	06/30/2023
TPL-001-4	4.2.		01/01/2016	06/30/2023
TPL-001-4	4.3.		01/01/2016	06/30/2023
TPL-001-4	4.3.1.		01/01/2016	06/30/2023

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: TPL-001-4 — Transmission System Planning Performance Requirements

<u>United States</u>

TPL-001-4	4.3.1.1.		01/01/2016	06/30/2023
TPL-001-4	4.3.1.2.		01/01/2016	06/30/2023
TPL-001-4	4.3.1.3.		01/01/2016	06/30/2023
TPL-001-4	4.3.2.		01/01/2016	06/30/2023
TPL-001-4	4.4.		01/01/2016	06/30/2023
TPL-001-4	4.4.1.		01/01/2016	06/30/2023
TPL-001-4	4.5.		01/01/2016	06/30/2023
TPL-001-4	8.1.		01/01/2016	06/30/2023

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-010

Request:

Submit the Transmission Center Inspections Reports.

Response:

Please refer to the transmission substation inspections data in RFI-LUMA-MI-21-0001-210406-PREB-010 Attachment 1. This material was previously filed on April 12th in Initial Budgets (NEPR-MI-2021-0004) as RFI-LUMA-MI-21-0004-210405-PREB-005b Attachment 4.

System Operation Principles
Docket ID: NERP-MI-2021-0001

Information Response Round 1 to: PREB

Reference: RFI-LUMA-MI-21-0001-210406-PREB-011

Request:

Submit the Generation Plant Inspection Reports.

Response:

Please refer to the Generation Plant Assessment in RFI-LUMA-MI-21-0001-210406-PREB-011 Attachment 1. This material was previously filed on April 12th in Initial Budgets (NEPR-MI-2021-0004) as RFI-LUMA-MI-21-0004-210405-PREB-005d Attachment 3.

LUMA

Generation Team Plant Assessment November, 2020

I. PREPA Assessment of PREPA's Baseload Power Plants

- San Juan Plant
- Costa Sur Plant
- Palo Seco Plant
- Aguirre Plant

Physical Layout

[redacted]

[redacted]

Role In The System

[redacted]

[redacted]

[redacted]

Fuel-Related

[redacted]

[redacted]

[redacted]

Observations Similar to All Units

[redacted]

Observations Specific to San Juan

[redacted]

[redacted]

[redacted]

- [redacted]

- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

CONFIDENTIAL

San Juan Combined Cycle (Units 5 & 6) CIM data, has since been converted to LNG

[redacted]

CONFIDENTIAL

San Juan Steam Electric Station (Unit 7 – 10)

[redacted]

Physical Layout

[redacted]

[redacted]

Role In The System

[redacted]

[redacted]

[redacted]

Fuel-Related

[redacted]

Observations Similar to All Units

[redacted]

Observations Specific to Costa Sur

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Costa Sur

[redacted]

Costa Sur

[redacted]

CONFIDENTIAL

Costa Sur Steam Electric Station - Units 3 & 4

[redacted]

CONFIDENTIAL

Costa Sur Steam Electric Station – Units 5 & 6

[redacted]

Physical Layout

[redacted]

[redacted]

Role In The System

[redacted]

[redacted]

[redacted]

Fuel-Related

[redacted]

Observations Similar to All Units

[redacted]

Observations Specific to Palo Seco

[redacted]

[redacted]

Palo Seco

[redacted]

Palo Seco

[redacted]

CONFIDENTIAL

Palo Seco Steam Electric Station – Units 1 & 2

[redacted]

CONFIDENTIAL

Palo Seco Steam Electric Station – Units 3 & 4

[redacted]

Physical Layout

[redacted]

Role In The System

[redacted]

Fuel-Related

[redacted]

Observations Similar to All Units

[redacted]

Observations Specific to Aguirre

[redacted]

[redacted]

- [redacted]

[redacted]

Aguirre

[redacted]

Aguirre

[redacted]

CONFIDENTIAL

Aguirre Combined Cycle

[redacted]

CONFIDENTIAL

Aguirre Steam Electric Station

[redacted]