Review of 2023 RTEP Assumptions

Transmission Expansion Advisory Committee

January 10, 2023

2023 RTEP Assumptions

- 2023 RTEP
  - TPL-001-5 (Effective July 1, 2023): Details in the following slides
  - PJM criteria
  - TO 715 Criteria

- **TPL-001-5**
  - FERC Order issued approving TPL-001-5
  - Docket No. RM19-10-000
  - January 23, 2020
- **TPL-001-5.1**
  - FERC Order issued approving TPL-001-5.1
  - Docket No. RD20-8-000
  - June 10, 2020
    - Errata: Updates incorrect references made in Requirement R2 Part 2.7.
- Effective Date of Standard: 7/1/2023(1)
  - (1)Requirement R2 Part 2.7: 7/1/2025 – See Implementation Plan

- **Revisions**
  - Known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner
  - Six month outage duration removed
    - Known outage(s) shall not be excluded solely based upon outage duration.
  - Stability analysis now required in Requirement R2 Part 2.4.4.

- **Revisions**
  - Part 2.1.5

> **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~~assessed. Based upon this assessment, an~~The~~ ~~studies~~ analysis 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.

  - Stability analysis now required in Requirement R2 Part 2.4.5.
    - *"An analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES."*

- **Revisions**
  - Scope of P5 events will now include non-redundant components of a Protection System not just relays (Footnote 13)
    - Single protective relay
    - Single communications system
    - Single station DC supply
    - Single control circuitry
  - System performance to be evaluated under both steady state and stability conditions with new P5 contingencies.

TPL-001-5.1: SPF – Table 1 Planning Events

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[12]~~ component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

13. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows:

a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;

b. A single communications system associated with protective functions ~~or types: pilot (#85), distance (#21), differential (#87), current (#50, 51,~~ necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and ~~67),~~ reported at a Control Center);

c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67), and tripping (#86, & 94),~~ and open circuit);

d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

TPL-001-5.1: SPF – Table 1 Extreme Events

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.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   ~~e.~~i. 3Ø internal breaker fault.
   ~~f.~~j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Expected Timeline

- November 2022: Establish 2023 RTEP base case modeling assumptions November 2022 to February 2023: Build base cases and perform initial case review. During this period,
  - New modeling and other basic assumption changes will not be considered unless PJM determines they may have a significant impact on the RTEP baseline studies.
  - Corrections to the analytical files will be accepted.
- February to June 2023: Perform RTEP baseline studies.
  - No new modeling or other basic assumption changes anticipated unless PJM determines they may have a significant impact on the RTEP baseline studies.
  - Corrections to the analytical files will only be accepted if they have a widespread impact or will likely impact one or more identified violations.

Expected Timeline

- June/July 2023 (This time line might be impacted by Data Center window scheduled for Q1 2023.)
  - Open competitive proposal window
  - Post modeling assumptions changes and corrections for and begin mid-year retool of 2023 RTEP baseline analysis if required
    - Accounts for major new modeling assumption changes and corrections not previously considered.
    - Basic assumptions such as planning criteria and ratings methodology that changed after February will not be considered until the 2024 RTEP.
- July/August 2023
  - Close competitive proposal window
  - Finalize mid-year retool
- August to December 2023: Evaluate proposals
- October 2023 to February 2024: Approve proposals

2023 RTEP Model Assumptions

- Load Flow Modeling
  - Power flow models for outside world load, capacity, and topology will be based on the following 2022 Series MMWG power flow cases
    - 2027SUM MMWG outside world for 2023 Series 2028SUM RTEP, 2026SUM RTEP
    - 2027LL MMWG outside world for 2023 Series 2028LL RTEP
    - 2027 WIN MMWG outside world for 2023 Series 2028WIN RTEP, 2026WIN RTEP
    - 2024SUM MMWG outside world for 2023 Series 2024SUM RTEP
  - PJM to work with neighbors to identify any updates to topology/corrections
  - PJM topology for all cases sourced from Model On Demand
    - Include all PJM Board approved upgrades through the December 2022 PJM Board of Manager approvals as well as all anticipated February 2023 PJM Board approvals
    - Include all Supplemental Projects included in 2022 Local Plan

- Firm Commitments
  - Long term firm transmission service consistent with those coordinated between PJM and other Planning Coordinators during the 2022 Series MMWG development
- Outage Rates
  - Generation outage rates will be based on the most recent Reserve Requirement Study (RRS) performed by PJM
  - Generation outage rates for future PJM units will be estimated based on class average rates

- At a minimum, all PJM bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM will be monitored.
- At a minimum, contingency analysis will include all bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM.
- Thermal and voltage limits will be consistent with those used in operations and those specified in the Form 715 planning criteria. In all cases, the more conservative value will be used.

2023 RTEP Load Modeling

- Summer Peak Load
  - Summer Peak Load will be modeled consistent with the 2023 PJM Load Forecast Report (or most updated load forecast)
  - The final load forecast released in December 2022
- Winter Peak Load
  - Winter Peak Load will be modeled consistent with the 2023 PJM Load Forecast Report
- Light Load
  - Modeled at 50% of the Peak Load forecast per M14B
  - The Light Load Reliability Criteria case will be modeled consistent with the procedure defined in M14B
- Load Management, where applicable, will be modeled consistent with the 2023 Load Forecast Report
  - Used in LDA under study in load deliverability analysis

2023 RTEP Generation Assumptions

- All existing generation expected to be in service for the year being studied will be modeled.
- Future generation with a signed Interconnection Service Agreement (ISA)*, or that cleared in the 2023/24 BRA, will be modeled along with any associated network upgrades.
  - Generation with a signed ISA will contribute to and be allowed to back-off problems.
  - *Following the implementation of the Interconnection Process Reform – Terminology will be updated from ISA to Generation Interconnection Agreement (GIA), which will include Interconnection Construction Terms and Conditions.
- Generation with a System Facility study will be modeled consistent with the procedures noted in Manual 14B, is not expected to be required to meet target generation levels through the planning horizon, and therefore will not be considered in the RTEP analysis.
- Additional generation information (i.e. machine lists) will be posted to the TEAC page.
- NJ OSW capacity stage consideration (split between 2028 and 2030 to account for ISDs)

Deactivation Notification Generation

- Generation that has officially notified PJM of deactivation will be modeled offline in RTEP base cases for all study years after the intended deactivation date
- RTEP baseline upgrades associated with generation deactivations will be modeled
- Retired units Capacity Interconnection Rights are maintained in RTEP base cases for 1 year after deactivation at which point they will be removed unless claimed by an queue project

PSEG/NY Interface

- PJM/NYISO Interface
  - B & C cables will be modeled out of service consistent with 2022 RTEP
- Linden VFT
  - Modeled at 330 MW
- HTP
  - Modeled at 0 MW

High Impact Projects Included

- OSW
  - Capacity modeling (consideration of staging: 5 year vs. 8 year)
  - Reinforcements (consideration of staging: 5 year vs. 8 year)
- Data Center Load
  - 2023 Load Forecast includes Dominion data center load projections
  - Potential inclusion of supplemental project upgrades, which are not in 2022 local plan

- The total 6,400 MW offshore wind injection will be modeled similar to how Capacity Interconnection Rights are maintained for retired generator.
  - Capacity staging will be taken into account in 5 and 8 year cases
- The required upgrades/transmission overlay identified through the NJ SAA window will be modeled.
  - Transmission staging will be taken into account in 5 and 8 year cases

- **2023 RTEP 2028 near-term base case:** Not consider generation and transmission changes beyond 6/1/2028 that may mask reliability issues in the five year horizon.

Solicitation #	Queue(s)	Project	Generation ISD	2028 Base Case	Transmission ISD	2028 Base Case
1	AE1-020, -104	OW1	12/31/2024	Online	< 12/31/2024	In Service
2a	AE2-020,-021,-022	ASOW1	4/30/2028	Online	< 4/30/2028	In Service
2b	AG2-055	OW2 Smithburg	1/31/2029	Offline but able to contribute	12/31/2027	In Service
3		LCD Smithburg POI	2030	Not modeled	12/31/2027	In Service
4		LCD Larrabee POI	2031	Not modeled	6/1/2029	Not in service
5		LCD Atlantic POI	2033	Not modeled	6/1/2030	Not in service

- **2023 RTEP 2030 long-term base case:** Consider approved generation and transmission changes projected to be in service in the 15 year horizon.

Solicitation #	Queue(s)	Project	Generation ISD	2030 Base Case	Transmission ISD	2030 Base Case
1	AE1-020, -104	OW1	12/31/2024	Online	< 12/31/2024	In Service
2a	AE2-020,-021,-022	ASOW1	4/30/2028	Online	< 4/30/2028	In Service
2b	AG2-055	OW2 Smithburg	1/31/2029	Online	12/31/2027	In Service
3		LCD Smithburg POI	2030	Online	12/31/2027	In Service
4		LCD Larrabee POI	2031	Online	6/1/2029	In Service
5		LCD Atlantic POI	2033	Online	6/1/2030	In Service

New Base Case Dispatch & Generator Deliverability Procedure Changes

- As part of the 2023 RTEP, PJM expects to begin applying the new generator deliverability procedures and associated base case dispatch procedures that are up for endorsement at the PC and MRC by February 2023
- The new procedure requires PJM to annually post regional assumptions related to the dispatch of wind and solar resources for summer, winter and light load conditions
  - Base Case dispatch (Capacity Factor)
  - Harmer dispatch (P80% or P90%)
  - Helper dispatch (P20%)

Capacity Factors For Wind & Solar Base Case Dispatch As Percent of Maximum Facility Output

MAAC	Summer CF*	Winter CF	Light Load CF
Solar Fixed	47%	5%	52%
Solar Tracking	64%	5%	56%
Onshore Wind	16%	40%	29%
Offshore Wind	38%	55%	46%

PJM West	Summer CF*	Winter CF	Light Load CF
Solar Fixed	54%	5%	53%
Solar Tracking	65%	5%	54%
Onshore Wind	19%	43%	34%
Offshore Wind	N/A	N/A	N/A

DOM	Summer CF*	Winter CF	Light Load CF
Solar Fixed	55%	5%	59%
Solar Tracking	66%	5%	58%
Onshore Wind	20%	41%	32%
Offshore Wind	33%	57%	49%

*** Use lower of CIR or Capacity Factor (CF)**

Wind & Solar Harmer Dispatch
As Percent of Maximum Facility Output

MAAC	Summer**	Winter	Light Load
Solar Fixed ($P_{80\%}$)	67%	*	*
Solar Tracking ($P_{80\%}$)	89%	*	*
Onshore Wind ($P_{90\%}$)	38%	73%	66%
Offshore Wind ($P_{80\%}$)	73%	96%	90%

PJM West	Summer**	Winter	LL
Solar Fixed ($P_{80\%}$)	76%	*	*
Solar Tracking ($P_{80\%}$)	84%	*	*
Onshore Wind ($P_{90\%}$)	52%	84%	80%
Offshore Wind ($P_{80\%}$)	N/A	N/A	N/A

DOM	Summer**	Winter	LL
Solar Fixed ($P_{80\%}$)	77%	*	*
Solar Tracking ($P_{80\%}$)	85%	*	*
Onshore Wind ($P_{90\%}$)	45%	78%	71%
Offshore Wind ($P_{80\%}$)	68%	98%	93%

*** Not applicable**

****CIR level will be used for summer, single contingency testing**

Wind & Solar Helper Dispatch
As Percent of Maximum Facility Output

MAAC	Summer $P_{20\%}$	Winter $P_{20\%}$	Light Load ($P_{20\%}$)
Solar Fixed	28%	0%	22%
Solar Tracking	38%	0%	22%
Onshore Wind	0%	15%	5%
Offshore Wind	0%	13%	6%

PJM West	Summer $P_{20\%}$	Winter $P_{20\%}$	Light Load ($P_{20\%}$)
Solar Fixed	33%	0%	21%
Solar Tracking	43%	0%	26%
Onshore Wind	0%	13%	5%
Offshore Wind	N/A	N/A	N/A

DOM	Summer $P_{20\%}$	Winter $P_{20\%}$	Light Load ($P_{20\%}$)
Solar Fixed	35%	0%	32%
Solar Tracking	48%	0%	30%
Onshore Wind	0%	17%	8%
Offshore Wind	0%	13%	7%

Generator Deliverability: Generic EEFORds

- Generic EEFORd values developed for 2028 RTEP base case
- Capacity weighted by fuel type
  - Each unit within a given generator class is assigned the average EEFORd for that class

24 Month RTEP

- As part of the 24-month RTEP cycle, a year 7 (2030) base case will be developed and evaluated as needed as part of the 2023 RTEP
- The year 7 case will be based on the 2028 Summer case that will be developed as part of this year's 2023 RTEP
- Purpose: To identify and develop longer lead time transmission upgrades

FERC 1000 Process

- Similar to the 2022 RTEP and per the PJM Operating Agreement, a proposal window will be conducted for all reliability needs that are not certain Immediate Need reliability upgrades or are otherwise ineligible to go through the window process.

- FERC 1000 implementation will be similar to the 2022 RTEP.
  - Advance notice and posting of potential violations
  - Advance notice of window openings
  - Window administration

Locational Deliverability Areas (LDAs)

- Includes the existing 27 LDAs
- Total of 27 LDAs
  - All 27 to be evaluated as part of the 2023 RTEP

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, Comed, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
Comed	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

Request stakeholder suggestions for and input to 2023 alternative sensitivity studies and scenario analysis

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2023 RTEP Assumptions

PROTECT THE POWER GRID

THINK BEFORE YOU CLICK!

Be alert to malicious phishing emails.

Report suspicious email activity to PJM.

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Revision History

Version No.	Date	Description
1	1/6/2023	• Original slides posted