Review of 2019 RTEP Assumptions Update

Transmission Expansion Advisory Committee
March 7, 2019
• Update of standard RTEP assumptions
• 2019 RTEP
  – TPL-001-4
• Modeling
  – MOD-032 (GOs and TOs)
    • Siemens PSS®MOD - Model On Demand (TOs)
    • PJM.com Planning Center Online Tool (Gen Model) – GOs
• RTEP Proposal Windows

(No change from February presentation)
• **Load Flow Modeling**
  - Power flow models for outside world load, capacity, and topology will be based on the following 2018 Series MMWG power flow cases
    - 2018 Series 2023SUM MMWG outside world for
      - 2019 Series 2024SUM RTEP, 2022SUM RTEP
    - 2018 Series 2023SLL MMWG outside world for
      - 2019 Series 2024LL RTEP
    - 2018 Series 2023WIN MMWG outside world for
      - 2019 Series 2024WIN 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 2018 PJM Board of Manager approvals as well as all anticipated February 2019 PJM Board approvals
  - OVEC will be included as a part of PJM

(No change from February presentation)
Locational Deliverability Areas (LDAs)

- Includes the existing 27 LDAs
  - Total of 27 LDAs
    - All 27 to be evaluated for the 2022/2023 delivery year RPM base residual auction planning parameters

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

(No change from February presentation)
2019 RTEP Assumptions

• Firm Commitments
  – Long term firm transmission service consistent with those coordinated between PJM and other Planning Coordinators during the 2018 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 (No change from February presentation)
Generator Deliverability: Generic EEFORds

- Generic EEFORd values developed for 2024 RTEP base case
  - To be posted with TEAC materials
- Capacity weighted by fuel type
  - Each unit within a given generator class is assigned the average EEFORd for that class

<table>
<thead>
<tr>
<th>Gen Class</th>
<th>MW</th>
<th>Avg EEFORD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil Steam</td>
<td>61,723</td>
<td>8.35%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>28,830</td>
<td>1.49%</td>
</tr>
<tr>
<td>Combustion Turbine</td>
<td>26,915</td>
<td>9.09%</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>62,055</td>
<td>3.35%</td>
</tr>
<tr>
<td>Hydro</td>
<td>2,927</td>
<td>7.23%</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>5,609</td>
<td>3.39%</td>
</tr>
<tr>
<td>Diesel</td>
<td>999</td>
<td>12.33%</td>
</tr>
<tr>
<td>Wind</td>
<td>2,031</td>
<td>0.00%</td>
</tr>
<tr>
<td>Solar</td>
<td>1,739</td>
<td>0.00%</td>
</tr>
</tbody>
</table>

(No change from February presentation)
• Summer Peak Load
  – Summer Peak Load will be modeled consistent with the 2019 PJM Load Forecast Report
  – The final load forecast released in December 2018

• Winter Peak Load
  – Winter Peak Load will be modeled consistent with the 2019 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 2019 Load Forecast Report
  – Used in LDA under study in load deliverability analysis
  – Include Demand Response (DR) based on what cleared in the 2021/22 BRA

(No change from February presentation)
• All existing generation expected to be in service for the year being studied will be modeled.
• Future generation with a signed Interconnection Service Agreement, or that cleared in the 2021/22 BRA, will be modeled online along with any associated network upgrades.
• Generation with an FSA will be modeled offline but will be allowed to contribute to problems in the generation deliverability sensitivity testing for years 6 through 15
  – Generation with an executed FSA will not be allowed to back-off problems.
• Additional generation information (i.e. machine lists) will be posted to the TEAC page.

(Updated FSA modeling to reflect revised Manual M14B Attachment C language endorsed in February)
A few new load deliverability procedures in Manual 14B were endorsed in February

- Non-radial facilities 345 kV and up will only automatically be considered as CETL limits for an LDA if they have greater than a 2% OTDF
- PJM may choose to include specific non-PJM transmission facilities in the load deliverability test in order to account for significant loop flows
- Both thermal and voltage analysis on both Discrete Outage Case and Mean Dispatch Case will be examined
- Mean thermal loadings will be used instead of median thermal loadings

(New slide to reflect revised Manual M14B Attachment C language endorsed in February)
Queue Project NOT Included in 2019 Series RTEP Cases

- Queue projects with an FSA or ISA but are not included in 2019 Series RTEP cases
  - X3-028 (MTX)
    - 2000 MW Energy Transmission Injection Rights and 1500 MW Capacity Transmission Injection Rights
  - Y3-092 (MTX)
    - 1000 MW Capacity Transmission Injection Rights
    - 500 MW Firm Transmission Withdrawal Rights and 500 MW Non-Firm Transmission Withdrawal Rights

(No change from February presentation)
• 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 interconnection queue project

(No change from February presentation)
• 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.

(No change from February presentation)
• PJM/NYISO Interface
  – B & C cables will be modeled out of service consistent with NYISO modeling

• Linden VFT
  – Injection: Modeled at 315 MW Capacity Transmission Injection Rights

• HTP
  – Modeled at 673 MW Non-Firm Transmission Withdrawal Rights

(No change from February presentation)
As part of the 24-month RTEP cycle, a year 7 (2026) base case will be developed and, as necessary, evaluated as part of the 2019 RTEP.

The year 7 case will be based on the 2024 Summer case that will be developed as part of this year’s 2019 RTEP.

- The case will be updated to be consistent with the 2019 RTEP assumptions.

Purpose: To identify and develop longer lead time transmission upgrades.

(Updated required evaluation of year 7 case to reflect revised Manual M14B language endorsed in February)
• Similar to the 2018 RTEP and per the PJM Operating Agreement, a proposal window will be conducted for all reliability needs that are not Immediate Need reliability upgrades or are otherwise ineligible to go through the window process.

• FERC 1000 implementation will be similar to the 2018 RTEP.
  – Advance notice and posting of potential violations
  – Advance notice of window openings
  – Window administration

(No change from February presentation)
• Request stakeholder suggestions for and input to 2019 alternative sensitivity studies and scenario analysis

(No change from February presentation)
V1 – 2/25/2019 – Original Slides Posted