Transmission Expansion Advisory Committee

December 13, 2012
Issues Tracking
• Open Issues
  – None

• New Issues
2013 RTEP Assumptions
Overview

- Update of standard assumptions
- Scenario & Sensitivity analysis
- TEAC input & feedback
2013 RTEP Assumptions

• Load Flow Modeling

  – Power flow models for world load, capacity and topology will be based on the 2018 summer case from the 2012 ERAG MMWG series power flow base case

  – Update of adjacent areas with latest topology

  – PJM topology will be based on the 2017 RTEP case that was used in the 2012 RTEP
    • Include all PJM Board approved upgrades through the December 5, 2012 PJM Board of Manager approvals as well as all anticipated February 2013 PJM Board approvals

  – East Kentucky Power Cooperative (EKPC) included
Locational Deliverability Areas (LDAs)

- Includes the existing 25 LDAs.

- East Kentucky Power Cooperative (EKPC) included
  - Was also part of the 2012 RTEP

- Recently implemented Cleveland LDA

- Total of 27 LDAs
  - All 27 to be evaluated for 2016/2017 delivery year RPM base residual auction
2013 RTEP Assumptions

• Firm Commitments
  – Long term firm transmission service will be consistent with operations

• 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
• Peak Load
  – Load will be modeled consistent with the 2013 PJM Load Forecast Report
  – The final load forecast data is expected to be available late December 2012
  – Include Demand Response (DR) and Energy Efficiency (EE) that cleared in the
    2015/16 BRA

• 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
  2013 Load Forecast Report
  – Used in LDA under study in load deliverability analysis
2013 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 will be modeled along with any associated upgrades.
  
  – Generation with a signed ISA will contribute to and be allowed to back-off problems.

• Generation with an executed Facility Study Agreement (FSA) will be modeled along with any associated network upgrades.
2013 RTEP Generation Assumptions

- Generation with an FSA will be modeled consistent with the procedures noted in manual 14B.

- Generation with an executed FSA will be modeled off-line but will be allowed to contribute to problems in the generation deliverability testing.
  - Generation with an executed FSA will not be allowed to back-off problems.

- If the PJM load exceeds the sum of the available generation and generation with an executed ISA then queued generation that has an executed FSA will be turned on to meet firm interchange.

- Additional generation information (i.e. machine lists) will be posted to the TEAC page.
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.
2013 RTEP Assumptions

• All PJM bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM will be monitored.

• Contingency analysis will include all bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM.
  – Contingencies in neighboring systems

• Thermal and voltage limits will be consistent with those used in operations.
As part of the 24-month RTEP cycle, a year 7 (2020) base case will be developed and evaluated as part of the 2013 RTEP.

The year 7 case will be based on the 2020 case that was developed as part of this year’s RTEP.
- The case will be updated to be consistent with the 2013 RTEP assumptions.

Purpose: To identify and develop longer lead time transmission upgrades.
2013 Scenario Analysis

• Recap of 2012 RTEP
  – Renewable Portfolio Standards (RPS)
  – At-Risk Generation
  – High Load Growth Forecast

• 2013 RTEP Potential Scenarios
Stakeholder Input and Review of Assumptions and Scenarios

• Assumptions review

• Scenarios review

• Email RTEP@pjm.com
2012 RTEP Scenario Analysis
2012 RTEP Scenario Analysis - At Risk Generation
At-Risk Generation

- **Assumptions**
  - Same as 2012 RTEP base except “at-risk” generation
  - Total 6362 MW plus Oyster Creek (614 MW) “at-risk” generation

- **Analysis**
  - Reliability Analysis monitored 230 kV and above facilities
    - Generator Deliverability (50/50 load level)
      - Thermal
    - Common Mode Outage test (50/50 load level)
      - Thermal
    - Load Deliverability (90/10 load level)
      - MAAC (Thermal and voltage)
      - EMAAC (Thermal and voltage)
    - N-1-1 (50/50 load level)
      - Thermal and Voltage
At-Risk Generation

- Results of 15 year analysis
  - PJM Mid-Atlantic Thermal Overloads
    - 4 - 500/230 kV transformers
    - >20 - 230 kV circuits
  - PJM South Thermal Overloads
    - 1 – 500/230 kV transformer
    - 6 – 230 kV circuits
  - PJM West Thermal Overloads
    - 4 – 345 kV circuits
  - EMAAC Voltage
    - Potential voltage violations for several contingencies
  - N-1-1
    - Several thermal and voltage potential violations
At-Risk Generation – Thermal Overloads
Consider Queued FSA Generation

- The At-Risk analysis was performed assuming the worst case scenario, where no new generation will be built. However PJM have several queue projects in FSA stage with historical probability of 56% of them moving forward
  - FSA generators in PJM → 13,000+ MW
  - FSA generators in MAAC → 9,000+ MW

- Consider modeling 56% of the FSA generation MW’s and re-evaluate
At-Risk Generation – Next Steps

• Re-run analysis assuming some amount of the FSA generation will move forward and go into service

• Evaluate result to determine any action plan resulting from at-risk generation
2012 RTEP
Renewable Portfolio Standards (RPS) Scenarios
RPS
Overview
Renewable Portfolio Standards

• Overall Assumptions
  – Model the latest Renewable Portfolio Standards (RPS) state targets
    • Assume production from renewable wind
    • Update target PJM installed renewable MW requirements
    • Update installed reserve calculation
  – 2012 PJM Load Forecast Report
    • 15 Year Load Forecast
    • Include Demand Response (DR) and Energy Efficiency (EE)
  – Incorporate findings from 2011 RTEP RPS scenario studies
RPS – Scenario #1

- Assumptions
  - Assume RPS supply from PJM resources
  - 7 GW Offshore
  - Study year: 2027

- Analysis
  - Reliability Analysis
    - Generator Deliverability (50/50 load level)
    - Common Mode Outage test (50/50 load level)
  - Market Efficiency Analysis
    - Security Constrained Optimal Power Flow (SCOPF)
    - Production cost simulation using PROMOD

- Result
  - Thermally overloaded facilities
  - Congestion $’s
  - Develop transmission overlay
### 2027 RPS Study

| Target Installed Nameplate for Renewables based on State Targets* | Solar | 7,600 |
| Wind | 35,600 |
| Total | 43,200 |

| Existing Installed Nameplate | Solar | 192 |
| Wind | 6,038 |
| Total | 6,228 |

| Forecast Restricted Demand ** (2012 PJM Load Forecast) | 169,539 |
| Installed Reserve Margin | 20% |
| Installed Capacity Needed | 203,447 |

| Installed Capacity Credit for new Renewables based on State Targets*** | Solar | 2,820 |
| Wind | 4,430 |
| Total | 7,250 |

| Current Installed Capacity | 184,562 |
| Pending Deactivations | 14,216 |
| Expected Non-Renewable Capacity in 2017 Base Case | 12,173 |
| Expected Non-Renewable Capacity Scheduled after 2017 | 2,120 |
| Additional Capacity Needed | 11,558 |

### Capacity Factors

<table>
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<tr>
<th>Location</th>
<th>Onshore</th>
<th>Offshore</th>
<th>Solar</th>
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<tr>
<td>Delaware</td>
<td>36%</td>
<td>19%</td>
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* Capacity factors will be based on PRIS Task 2 Scenario Development - Final Report
** Assumes ~15,000 MW of DR
*** Assumes 38% for solar and 15% for wind
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<td><strong>Total</strong></td>
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**Generator Interconnection projects that are not yet in service and are modeled in the 2012 RTEP 2017 base case**

**Based on amount of wind & solar projected in each PJM state in GE PRIS Task 2 Scenario Development - Final Report**
RPS – Scenario #1
RPS – Scenario #2

- **Assumptions**
  - **Low GW Offshore**
  - Otherwise, same as RPS – Scenario #1 but with a low GW offshore assumption (1,521 MW)
  - The remainder of the state target RPS will be sourced from inland PJM resources
**RPS Scenario #2**

**MODELED NAMEPLATE MW**

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<tr>
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<th>Queue*</th>
<th>Additional**</th>
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**Other Resources To Meet IRM**

| Natural Gas | 9,123 |
| Nuclear     | 3,425 |
| Other (Coal, Diesel, Oil, etc.) | 1,745 |

*Generator interconnection projects that are not yet in service and are modeled in the 2012 RTEP 2017 base case

**Based on amount of wind & solar projected in each PJM state in GE PRIS Task 2 Scenario Development - Final Report**
Scenario #2 Reliability Constraints
RPS – Scenario #3

• Assumptions
  – RPS Source from Neighboring Entities
  – Otherwise, same as RPS – Scenario #2 (low MW offshore)
  – The remainder of the state target RPS will be sourced from inland PJM resources

• Neighboring Entities
  – Assume 40% of the PJM RPS supplied from renewable wind in the Midwest ISO (MISO)
    • Assume DC injection points from external areas to PJM
### RPS Scenario #3

#### Modeled Nameplate MW

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<tr>
<th>Solar</th>
<th>Existing</th>
<th>Queue*</th>
<th>Additional**</th>
<th>TOTAL</th>
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* Generator Interconnection projects that are not yet in service and are modeled in the 2012 RTEP 2017 base case

** Based on amount of wind & solar projected in each PJM state in GE PRIS Task 2 Scenario Development - Final Report

*** Assumes 38% capacity factor
RPS Scenario #3
Transmission Overlay

- Developed by considering both reliability analyses and market efficiency analysis

- Reliability analysis included generation deliverability as well as a power flow analysis that approximates PJM’s light load criteria

- Market efficiency analysis used production cost simulations and considered wind curtailment and congestion

- Files posted with detailed information on the overlay
RPS
Transmission Overlay Drivers
Transmission Overlay Driver – Wind Curtailment

Curtailment (% of available capacity)

- RPS1 - w/ DC - No Overlay
- RPS1 - w/ DC - w/ Overlay
- RPS1 - No DC - w/ Overlay
- RPS2 - No Overlay
- RPS2 - w/ Overlay
- RPS3 - No Overlay
- RPS3 - w/ Overlay

No Overlay
Transmission Overlay Driver - Load Payments

2027 Nominal Dollars

No Overlay

With Overlay
Transmission Overlay Driver – Congestion Total PJM

2027 Nominal Dollars

- No Overlay
- With Overlay

Bar chart showing costs in billions of dollars.

Legend:
- Non RPS Queue Based Expansion
- RPS1 - w/ DC - No Overlay
- RPS1 - w/ DC - w/ Overlay
- RPS1 - No DC - w/ Overlay
- RPS2 - No Overlay
- RPS2 - w/ Overlay
- RPS3 - No Overlay
- RPS3 - w/ Overlay

Costs:
- EMAAC
- Rest of MAAC
- Rest of PJM
RPS
Scenario Comparisons
Scenario Comparison – **Base** and Incremental Load Cost

*2027 Nominal Dollars

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<th>Annual Load Cost Differences Compared to RPS1 Base Cost</th>
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<td>RPS1 w/ Overlay, No DC w/ Overlay</td>
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<td>w/ DC</td>
<td><strong>$74 Billion</strong></td>
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<tr>
<td>w/ Overlay</td>
<td>0.4% Increase</td>
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Scenario Comparison – Incremental Load Cost

Load Payments Relative to RPS1 – w/ DC – w/ Overlay

Base Cost: $74B

2027 Nominal Dollars
## Congestion Cost Differences Compared to RPS1 Base Cost

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<th>RPS3 w/ Overlay</th>
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<td>w/ DC w/ Overlay</td>
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<td>$650 Million</td>
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2027 Nominal Dollars

www.pjm.com
Scenario Comparison – Incremental Congestion

Congestion Cost Relative to RPS1 – w/ DC – w/ Overlay
Base Cost: $650M

2027 Nominal Dollars
Scenario Comparison – Off Peak LMP

2027 Nominal Dollars

RPS1 - w/ DC - w/ Overlay
RPS1 - No DC - w/ Overlay
RPS2 – w/ Overlay
RPS3 - w/ Overlay
Scenario Comparison - Full Year, Off-Peak Load Weighted LMP

RPS1 w/ DC

RPS2

RPS1 No DC

RPS3

2027 Nominal Dollars

- 40
- 41.5
- 42.9
- 44.4
- 45.9
- 47.3
- 48.8
- 50.3
- 51.7
- 53.2
- 54.7
- 56.1
- 57.6
- 59.1
- 60.6
- 62
Scenario Comparison – Full Year, On Peak Load Weighted LMP

RPS1 w/ DC

RPS1 No DC

RPS2

RPS3

2027 Nominal Dollars

- 75
- 76.5
- 78.1
- 79.6
- 81.1
- 82.7
- 84.2
- 85.7
- 87.3
- 88.8
- 90.3
- 91.9
- 93.4
- 94.9
- 96.5
- 98
High Voltage in PJM Operations Analysis Update
Progress Update

• Determined potential reactor locations
  – from historical PI data and high voltage alarm data

• Modeled and simulated reactors in several operational cases to
determine the potential magnitude that is necessary to control high
voltage

• Also simulated high voltage conditions and reactors in a planning
case to determine system needs beyond the operational cases
High Voltage Locations from PJM Operations Cases

Locations noted in the 5 Cases from PJM Operations

Legend
Substation Violation Frequency
1
2
3
4
5
Progress Update

• Provided TOs with historic high voltage alarm data and voltage analysis performed on five historic EMS cases
• Currently gathering feedback from TOs
• Potential solutions received to date include
  – Shunt reactors
  – SVCs
  – Modifications to / optimization of existing facilities
    • Generator voltage schedules
    • Transformer tap settings
    • Switched shunt settings
• **AEC**
  – 50 MVAR shunt reactor at Mickleton 230 kV
  – +150/-100 MVAR SVC at Cedar 230 kV

• **AEP**
  – Under review

• **ComEd**
  – Optimization of existing facilities at Twin Grove and Kincaid

• **DLCO**
  – 200 MVAR shunt reactor at Brunot Island 345 kV
  – 200 MVAR shunt reactor on future Brunot Island – Carson 345 kV circuit
Preliminary Solutions

- **Dominion**
  - RTEP upgrades b1805, b2125 and b2126
- **DPL**
  - RTEP upgrades b0876 and b1899.1-b1899.3
- **FE**
  - Investigating optimization of existing facilities
  - Additional planning studies required
- **PPL**
  - 150 MVAR shunt reactor at Alburtis 500 kV
  - 100 MVAR shunt reactor at Elimsport 230 kV
  - Change generator voltage schedule at Montour
• PSEG
  – Near Term: Investigating optimization of existing facilities
  – Longer Term: Shunt reactors

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<th>Number</th>
<th>Size (MVAR)</th>
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<tr>
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<td>50</td>
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<td>Bergen</td>
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<td>50</td>
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<tr>
<td>Hudson</td>
<td>1</td>
<td>50</td>
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<tr>
<td>Stanley Tce</td>
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<td>50</td>
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<tr>
<td>West Orange</td>
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Generation Deactivation Notification
(Retirements) Update
• Essex 12
  - #121 – 46 MW
  - #122 – 46 MW
  - #123 – 46 MW
  - #124 – 46 MW
  - PSE&G Transmission Zone
  - 184 MW Total
  - Notification received 11/20/2012
  - Anticipated deactivation date 5/31/2015
  - Reliability Analysis underway. Capacity Interconnection rights to be re-used in interconnection project(s) T107, X3-004, and / or Y2-019
Ohio Area Deactivation Upgrade Alternative Analysis
Ohio Area Retirement Upgrades - Evaluation

• 2015 – 2017 analysis of criteria tests of the zones impacted by the Ohio area generation deactivations

• 2017 analysis including all recently approved upgrades

• Solution alternatives evaluated:
  o Marysville – South Amherst 765 kV
  o Trivalley – South Amherst 765 kV
  o Conesville – Beaver 345 kV
  o Conesville – Harmon 345 kV
  o Beaver Valley - Leroy Center 345kV + Mansfield – Leroy Center 345kV line
Ohio Area - 2017 Findings

- **Existing, approved RTEP transmission**
  - Existing approved baseline upgrade (B1977.1) - Build a new Toronto-Harmon 345kV line not needed in 2017 using current 2012 RTEP assumptions
  - Will re-evaluate B1977.1 need with 2013 RTEP assumptions

- **Solution alternatives considered:**
  - The following solution alternatives are not needed in 2017 with current 2012 RTEP assumptions
    - Marysville – South Amherst 765 kV
    - Trivalley – South Amherst 765 kV
    - Conesville – Beaver 345 kV
    - Conesville – Harmon 345 kV
    - Beaver Valley - Leroy Center 345kV + Mansfield – Leroy Center 345kV line
Ohio Area Retirement Upgrades – Next Steps

- Finalize 2015 – 2017 reliability criteria testing
- Review and recommend solutions to remaining criteria violations as well as any modification to approved transmission
- Evaluate the need for Toronto – Harmon 345 kV and proposed alternatives as part of the 2013 RTEP
15 Year Analysis Update
2012 RTEP 15 Year Planning Result

- Highest loading from applicable contingencies in all of the deliverability tests
- Conductor ratings applied
- Reinforcements may already be in development or approved for some of these potential issues

### Single Contingency Result

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<thead>
<tr>
<th>Fr Bus</th>
<th>Fr Name</th>
<th>To Bus</th>
<th>To Name</th>
<th>CKT</th>
<th>KVs</th>
<th>Areas</th>
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2012 RTEP 15 Year Planning Result

• Highest loading from applicable contingencies in all of the deliverability tests

• Conductor ratings applied

• Reinforcements may already be in development or approved for some of these potential issues

### Tower Contingency Result

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<tr>
<th>Fr Bus</th>
<th>Fr Name</th>
<th>To Bus</th>
<th>To Name</th>
<th>CKT</th>
<th>KVs</th>
<th>Areas</th>
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<td>BGE</td>
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</table>
2012 RTEP 15 Year Analysis Result

- Observations
  - Benchmark to year 8 (2020) case
- Next Steps
NERC Category A Violation

- Project b1506 – Scope change
  - Problem: Block load additions at NOVEC’s Gainesville DP is increasing load by 120-140 MW over the next several years. By summer 2012, the transformer feeding their DP will be above its emergency rating (269.1 MVA) under normal conditions.
  - Proposed Solution:
    - At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker
    - Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC’s DP at Gainesville
    - Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC’s Gainesville to Wheeler line.
    - Install 168MVA, 230/115kV transformer to feed NOVEC’s Gainesville-Wheeler line.
  - Estimated Project Cost $8.0 M
  - Projected IS Date: May 2013
• Project: b1910
• N-1-1 Thermal Violation
• Huntsman – Thrasher 230 kV is over its emergency rating for the loss of the Suffolk – Yadkin 500 kV and Fentress – Septa 500 kV lines
• Build a Suffolk – Yadkin 230 kV line (14 miles)
  – Install two 230 kV breakers at both Suffolk and Yadkin Substation to interconnect
  – Primarily along existing towers
• Estimated Project Cost: $40 M
• Old Projected IS Date: 6/1/2016
• Due to Yorktown 2 and Chesapeake 3&4 Retirements
• New Projected IS Date: 6/1/2015
Increase Cost Estimate:
- B210.1 (Orchard – Cumberland – Install second 230 kV line)
- The cost is increased as a result of changing the route of the circuit.
  The new scope includes re-building an existing 138 kV circuit to double circuit steel pole line so that a portion of the new 230 kV circuit will share the double circuit

Estimated Project Cost:
- Existing $ 4 M
- New $ 8 M

Expected IS Date:
- 12/31/2014
• The Bluebell 138 kV breaker ‘301-B-94’ is overstressed
• Proposed Solution: Revise the reclosing for the Bluebell 138 kV breaker ‘301-B-94’ (b2188)
• Estimated Project Cost: $25 K
• Expected IS Date: 06/01/2017
• The Brookside 138 kV breakers ‘701-B-59’ and ‘701-B-60’ are overstressed
• Proposed Solution: Revise the reclosing for the Brookside 138 kV breakers ‘701-B-59’ and ‘701-B-60’ (b2189-b2190)
• Estimated Project Cost: $25 K per breaker
• Expected IS Date: 06/01/2017
• The Longview 138 kV breaker ‘651-B-219’ and ‘651-B-32’ are overstressed
• Proposed Solution: Replace the Longview 138 kV breaker ‘651-B-219’ and ‘651-B-32’ (b2191-b2192)
• Estimated Project Cost: $175 K per breaker
• Expected IS Date: 06/01/2017
• The Lowellsville 138 kV breaker ‘110-B-4’ is overstressed
• Proposed Solution: Replace the Lowellsville 138 kV breaker ‘110-B-4’ (b2193)
• Estimated Project Cost: $175 K
• Expected IS Date: 06/01/2017
• The Riverbend 138 kV breaker ‘119-B-11’ is overstressed

• Proposed Solution: Replace the Riverbend 138 kV breaker ‘119-B-11’ (b2194)

• Estimated Project Cost: $175 K

• Expected IS Date: 06/01/2017
The Roberts 138 kV breaker ‘601-B-60’ is overstressed

Proposed Solution: Replace the Roberts 138 kV breaker ‘601-B-60’ (b2195)

Estimated Project Cost: $175 K

Expected IS Date: 06/01/2017
• The Sammis 138 kV breaker ‘780-B-76’ is overstressed

• Proposed Solution: Replace the Sammis 138 kV breaker ‘780-B-76’ (b2196)

• Estimated Project Cost: $175 K

• Expected IS Date: 06/01/2017
• The Salt Springs 138 kV breaker ‘105-B-35’ is overstressed

• Proposed Solution: Replace Salt Springs 138 kV breaker ‘105-B-35’ (b2197)

• Estimated Project Cost: $175 K

• Expected IS Date: 06/01/2017
Supplemental Projects
• **Supplemental Project**

• Add a 4th breaker to the Zion EC 345 kV bus to accommodate the Zion – Pleasant Prairie 345 kV (ATC) interconnection (S0502)

• Estimated Cost: $4.6M

• Projected IS Date: 06/01/2013
• Supplemental Project

• Change the no-load transformer taps from 338.25 kV to 346.5 kV at TSS 155 Nelson 345/138 substation. (S0503)

• Estimated Cost: $0.005M

• Projected IS Date: 06/01/2013
Next Steps
Questions?

Email: RTEP@pjm.com