Generator Deliverability Test Modifications: Light Load, Summer & Winter

Background/Purpose

- PJM is proposing modifications to each of the generator deliverability tests.
  - Procedures have been relatively unchanged for many years.
  - Multiple reasons for an update including a need better account for expected higher variability in dispatches under increased renewable penetration.
  - Better planning alignment with operations supporting operational flexibility.

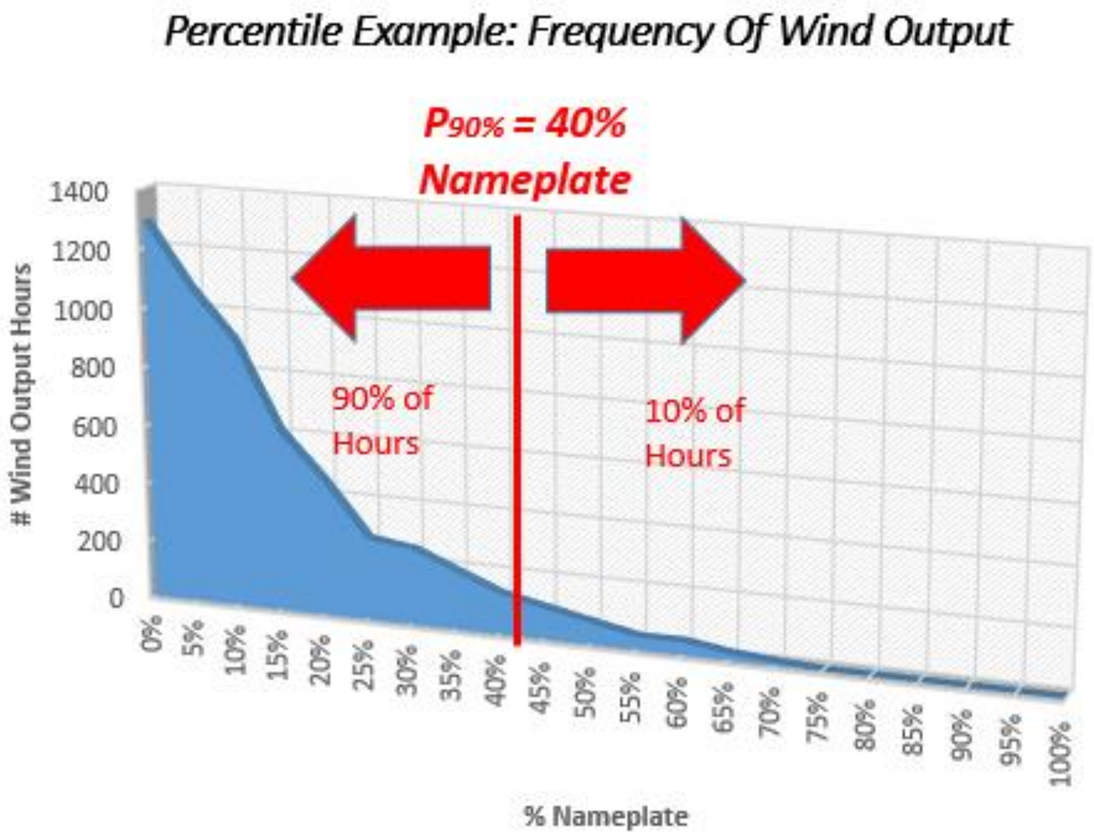
New Concepts

- The proposed changes to the generator deliverability test will use a few terms and concepts that warrant a brief overview.
- Deliverability Requirement (aka resource ramping limit): The seasonal MW injection capability associated with a Generation Capacity Resource and examined by the generator deliverability test that the transmission system must be designed to support to allow the resource to received a specified amount of CIRs.
  - A prerequisite to the award of CIRs
  - Applicable to individual Capacity Resources, e.g. the deliverability requirements of a new queue unit
  - Also applicable to combinations of Capacity Resources, e.g. the deliverability requirements of all reasonably expected combinations of CIRs
  - Can vary by PJM region and season
  - Applicable to summer, winter and light load generator deliverability testing

New Concepts

- Harmers and Helpers: These refer to Generation Capacity Resources that are electrically close to the flowgate by virtue of meeting certain DFAX and or impact thresholds.
  - Harmers: The DFAX is positive and an increase in the generation output would result in an increase in the loading on the flowgate under study.
  - Helpers: The DFAX is negative and a decrease in the generation output would result in an increase in the loading on the flowgate under study.

- Percentiles: Represent the percentage of output hours with output levels below a particular output level.
- Example: if the P90% (90th percentile) of onshore wind outputs is 40% of nameplate, this means that 90% of the time onshore wind is producing less than 40% of nameplate.



New Concepts

- Block Dispatch: Groups resource types into three distinct categories based on economic considerations with block 1 containing the units expected to have the lowest offer prices and block 3 to have the highest. Each block will be dispatched as whole and block 1 will be dispatched first, then block 2 and 3 as need
  - Block 1: Nuclear, wind, solar, hydro, pumped storage, other renewables
  - Block 2: Coal, combined cycle gas
  - Block 3: IC/CT/ST oil and gas
- Better matches how PJM will dispatch the system than status quo approach which relies on flat dispatch for summer and historic conditions to dispatch the winter and light load cases

- Energy-Only MW: The MW capability of a generator or of a Merchant Transmission Facility (MTF) that is not examined as part of the generator deliverability test. A facility's energy-only MW may be different for each season.
  - Example 1: A 100 MW gas unit requests 80 MW CIRs. The unit therefore has 20 MW of energy-only MW.
  - Example 2: A 100 MW MTF has 80 MW of firm transmission. The MTF therefore has 20 MW of energy-only MW.
  - Example 3: A 100 MW wind farm has a summer deliverability requirement of 40 MW. The unit therefore has 60 MW of summer energy-only MW.
  - Example 4: A 100 MW solar farm has a winter deliverability requirement of 5 MW. The unit therefore has 95 MW of winter energy-only MW.
- While energy-only MW will not be considered in the generator deliverability testing, they will be examined as part of a new Individual Plant Deliverability test to ensure the maximum output capability of each generating plant and MTF is deliverable by itself in each season.

Summary of Changes

- Merged summer, winter and light load generator deliverability testing methods
- Harmonized dispatch procedures for all three RTEP base cases
  - Added new block dispatch approach to dispatch cases. No LDA allowed to import more than CETO in base case to ensure a realistic dispatch.
  - Only firm interchange modeled in base cases with separate procedures for performing sensitivities on historical interchange using simplified approach
- Redefined light load period to include daytime hours from 10AM-3PM between 40-60% annual peak load
  - Established 59 deg F as default light load temperature rating set but allow individual TOs to select different temperature rating sets
  - Ramping procedures include both wind and solar
  - Ramping levels to consider variations during daytime hours

Summary of Changes

- Better account for volatility of wind and solar by using $P_{80\%}$-$P_{90\%}$ for Harmers and $P_{20\%}$ for Helpers in all generator deliverability tests
- Wind and solar Harmers and Helpers will now be handled independently from the 50/50 generation and Facility Loading Adders
  - Wind and solar generators
    - Harmer generators: Ramped up to $P_{80\%}$-$P_{90\%}$
    - Helper generators: Ramped down to $P_{20\%}$
  - Non-wind and non-solar generators
    - 50/50 generators: Ramped to full output (summer and winter only)
    - Facility Loading Adders generators: Ramped to based case output levels for the resource type

Summary of Changes

- Replaced all ramping caps with the following rules
  - Harmers
    - The total amount of online 50/50 and Facility Loading Adder generation will be limited to PJM online PGEN * PJM Avg EEFORd
    - The total amount of wind and solar Harmer generation ramped up will be limited to PJM online PGEN * PJM Avg EEFORd
  - Helpers:
    - The total amount of wind and solar Helper generation that is ramped down will be limited to the amount of Harmers
- Facility Loading Adders modelled at base case setting for resource type instead of 85%
- Facility Loading Adders will only be considered in summer studies since this is where the extra generation may be required

Summary of Changes

- Single contingency and common mode outage testing is now identical except for the DFAX cutoff – no more 80/20, only 50/50
- Energy-only portion of units not studied in generator deliverability but as part of new Individual Plant Deliverability test
- MISO wind considered in both light load and winter tests and option to consider other RTO renewables in the future
- Remove EEFORd for plants < 50 MW

Summary of Base Case Dispatch Changes For Wind & Solar

		Base Case Dispatch	
Period	Resource Type	Existing	Proposed*
Summer	Fixed Solar	38%	47-55%
Summer	Tracking Solar	~60%	64-66%
Summer	Onshore Wind	13%	16-20%
Summer	Offshore Wind	~30%	33-38%
Winter	Fixed Solar	5%	5%
Winter	Tracking Solar	5%	5%
Winter	Onshore Wind	33%	40-43%
Winter	Offshore Wind	60%	55-57%
Light Load	Fixed Solar	0%	52-59%
Light Load	Tracking Solar	0%	54-58%
Light Load	Onshore Wind	40%	29-34%
Light Load	Offshore Wind	60%	46-49%

* Proposed values vary based on which region resource is located in

Red Font = CIR MW

Summary of Harmer Ramping Levels For Wind & Solar

		Generator Deliverability Harmer Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing	Proposed*	Existing	Proposed*
Summer	Fixed Solar	38%	67-77%	100%	67-77%
Summer	Tracking Solar	~60%	84-89%	100%	84-89%
Summer	Onshore Wind	13%	38-52%	100%	38-52%
Summer	Offshore Wind	~30%	68-73%	100%	68-73%
Winter	Fixed Solar	10%	5%	100%	5%
Winter	Tracking Solar	10%	5%	100%	5%
Winter	Onshore Wind	80%	73-84%	100%	73-84%
Winter	Offshore Wind	80%	96-98%	100%	96-98%
Light Load	Fixed Solar	0%	78-87%	0%	78-87%
Light Load	Tracking Solar	0%	82-86%	0%	82-86%
Light Load	Onshore Wind	80%	66-80%	80%	66-80%
Light Load	Offshore Wind	80%	90-93%	80%	90-93%

* Proposed values vary based on which region resource is located in

Red Font = CIR MW

Summary of Helper Ramping Changes For Wind & Solar

		Generator Deliverability Helper Ramping			
		Single Contingency		Common Mode Outage	
Period	Resource Type	Existing*	Proposed**	Existing*	Proposed**
Summer	Fixed Solar	38%	28-35%	38%	28-35%
Summer	Tracking Solar	~60%	38-48%	~60%	38-48%
Summer	Onshore Wind	13%	0%	13%	0
Summer	Offshore Wind	~30%	0%	~30%	0
Winter	Fixed Solar	5%	0%	5%	0%
Winter	Tracking Solar	5%	0%	5%	0%
Winter	Onshore Wind	33%	15-17%	33%	15-17%
Winter	Offshore Wind	60%	13%	60%	13%
Light Load	Fixed Solar	0%	21-32%	0%	21-32%
Light Load	Tracking Solar	0%	22-30%	0%	22-30%
Light Load	Onshore Wind	40%	5-8%	40%	5-8%
Light Load	Offshore Wind	60%	6-7%	60%	6-7%

* Existing values are same as base case dispatch since Helpers are not adjusted

** Proposed values vary based on which region resource is located in

Red Font = CIR MW

Summary of Manual Changes

- Manual 14a Changes
  - Update references to account for Manual 14b changes
- Manual 14b Changes
  - Sections 2.3.6, 2.3.7, 2.3.10, 2.3.11, and 2.3.13
  - Attachments C.3, D-2 and D-3

Testing of New Proposal

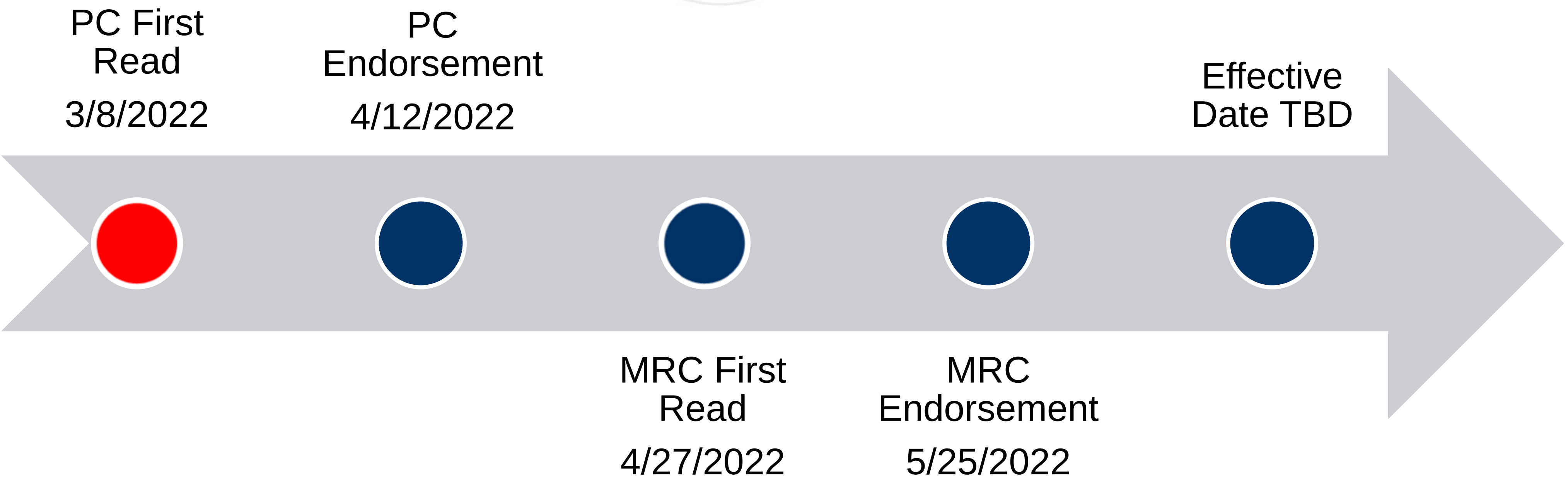
- Identify and summarize potential reliability violations for status quo and proposed generator deliverability procedures
  - 2026 RTEP Summer, Winter and Light Load
  - 2024 RTEP with hypothetical scenario using generation from the queue to simulate higher renewable penetration levels for Summer and Light load
- Plan to present results first at the February 23 special PC session and then again at the regular March 8th PC session

Queue Scenario Using CPs

- Using Impact Study Base Case (2024 RTEP Light Load & Summer) for AG1 queue
- Applying commercial probability forecast for IA Stage to reduce each queue unit's maximum output.
  - Example: 100 MW unit in the Impact Study stage has an 18% chance of reaching commercial operation so it is modelled as an 18 MW unit.

IA Stage	Commercial Probability
ISA	80%
Facilities	57%
Impact	18%

Review and Approval Timeline



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APPENDIX 1: Review of Existing Generator Deliverability Procedures

Light Load – Review of Existing Procedure

- Load level
  - 50% of annual peak
  - Representative of November through April 12AM-5AM
- Base case dispatch: Historic capacity factors by resource type
- Interchange:
  - Historical values from/to each external zone connected to PJM
  - Historical values inside PJM
- MISO wind: 100% output
- Generator ramping procedure: Wind units inside PJM ramp from 40 to 80% output based on electrical proximity to flowgate under study and all remaining online units are scaled down uniformly to compensate.

Light Load – Review of Existing Procedure

Network Model	Current year + 5 base case
Load Model	Light Load (50% of 50/50 summer peak)
Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)	Nuclear – 100% Coal >= 500 MW – 60% Coal < 500 MW – 45% Oil – 0% Natural Gas – 0% Wind – 40% All other resources – 0% Pumped Storage – full pump
Capacity Factor for Base Generation Dispatch for MISO Resources (Online in Base Case)	Wind – 100%
Interchange Values	Historical values
Contingencies	NERC P0, P1, P2, P4, P5 and P7
Monitored Facilities	All PJM market monitored facilities

Exhibit 5: Table 1 – Light Load Base Case Initial Target Dispatch

Table 2 – Light Load Study Generation Ramping Limits

Fuel Type	Ramping Limits (% of Pmax)
Nuclear	100%
Wind	80%
Coal >=500 MW	60%
Coal < 500 MW	45%
All other resources	0% (not ramped)

Summer – Review of Existing Procedure

- Load level
  - Each PJM area at its annual 50/50 summer peak
  - Representative of June, July & August
- Base case dispatch: Capacity Resources online and scaled uniformly to serve load, losses and firm interchange
- Interchange:
  - Firm from/to each external zone connected to PJM
- MISO wind: From MMWG case
- Generator ramping procedure: Up to full output based on proximity to flowgate, and all remaining online units are scaled down uniformly to compensate

Winter – Review of Existing Procedure

- Load level
  - Representative of December through February 5AM-9AM & 4PM-8PM
- Base case dispatch: Historic capacity factors by resource type
- Interchange:
  - Firm from/to each external zone connected to PJM
  - Historical values inside PJM
- MISO wind: From MMWG case
- Generator ramping procedure: Based on proximity to flowgate, and all remaining online units are scaled down uniformly to compensate
  - Wind units ramp from 33 to 80%
  - Solar ramp from 5 up to 10%
  - All other units ramp up to 100%

Winter – Review of Existing Procedure

Network Model	Current year + 5 base case
Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)	Solar – 5% Wind – 33% Water – 38% Nuclear – 98% Coal < 500 MW – 51% Coal >= 500 MW – 73% Landfill Gas – 46% Natural Gas – 25% Other Biomass Gas – 111% Oil (Distillate Fuel)– 1% Oil (Black Liquor)– 74% Oil (Kerosene)– 0% Oil (Residual Fuel)– 2% Municipal Solid Waste – 79% Wood Waste – 66% Waste Coal – 75% Petroleum Coke – 75% Other Solid – 19%
Interchange Values	Yearly long term firm (LTF) transmission service (except MAAC which will use historical averages)
Contingencies	NERC Category P0, P1, P2, P3, P4, P5, P6, and P7
Monitored Facilities	All PJM market monitored facilities

Exhibit 6: Table 1 – Winter Peak Base Case Initial Target Dispatch

Table 2 – Winter Peak Study Generation Ramping Limits

Fuel Type	Ramping Limits (% of Pmax)
Solar	10%
Wind	80%
All other resources	100%

APPENDIX 2: Detailed Changes To Generator Deliverability Test

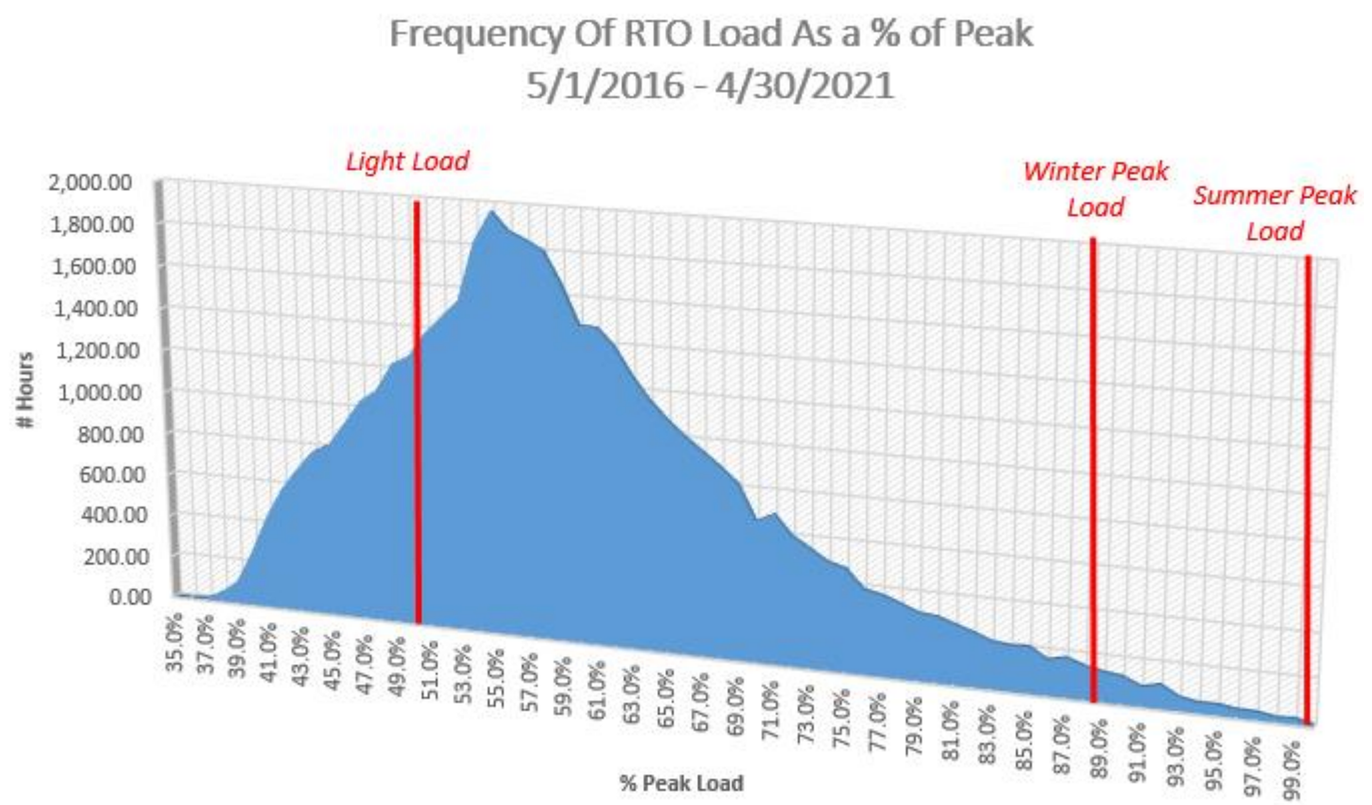
Proposed Modifications: Load Level

- **Load Level**
  - Proposal
    - Summer: No change
    - Winter: No change. Slight shift in evening hours from 4PM-8PM to 6PM-10PM based on recent loss of load studies.
    - Light load
      - Keep 50% of annual peak
      - Use daytime load hours from 10AM-3PM between 40% and 60% of the annual peak for historical generation data necessary to represent the 50% load level
  - Justification for change
    - Want to consider daytime hours instead of nighttime hours since wind levels are just about as high during the day but solar is much higher during the day
    - Also considered using minimum load level but that is extremely rare condition compared to 50% of peak which is a load level much closer to the range of load levels that occurs most frequently in PJM

Proposed Modifications: Load Level

- Graph illustrates number of hours at each PJM load level as a percentage of the annual peak load, and where on the histogram each of the three PJM generator deliverability periods is focused.

- Light load
  - ✓ 50% of peak load
  - ✓ 80% of load hours are above and 20% below
  - ✓ Captures higher concentration of load hours than summer and winter



Proposed Modification: Base Case Dispatch

- Block Dispatch
  - Block 1: Nuclear, wind, solar, hydro, pumped storage, other renewables
    - Nuclear at PMAX * (1 – PJM EEFORd)
    - Pumped storage at PMIN * (1 – PJM EEFORd) in light load and PMAX * (1 – PJM EEFORd) in summer & winter
    - Wind and solar at historic capacity factors for resource type, region and period
    - Hydro and other renewables at PMAX * (1 – PJM EEFORd)
  - Block 2: Coal, combined cycle gas
    - Turn on all units and scale up uniformly to meet system needs up to PMAX * (1 – EEFORd)
  - Block 3: IC/CT/ST oil and gas
    - Turn on all units and scale up uniformly to meet system needs up to PMAX * (1 – EEFORd)
- Notes
  - For summer period use CIRs in place of PMAX and historic capacity factor
  - Batteries offline
  - Block 2 & 3 dispatch will be modified as necessary for constraint control

Winter & Light Load Capacity Factors For Solar & Wind

MAAC	Summer CF**	Winter CF	LL CF 10AM-3PM
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	LL 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	LL CF
Solar Fixed	55%	5%*	59%
Solar Tracking	66%	5%*	58%
Onshore Wind	20%	41%	32%
Offshore Wind	33%	57%	49%

*** No change from status quo assumptions**

**** Only used for Facility Load Adders**

Proposed Modification: Base Case Dispatch

- Justification for change
  - Adopt a simplified dispatch that seeks to simulate economic conditions
  - Appears to match well with historical regional dispatch patterns
  - Status quo relies only on historic capacity factors and therefore can’t keep up with rapidly evolving resource mix

Proposed Modifications: External Interchange

- Continue to maintain firm interchange in base cases and account for historical utilization in the test
- Continue to preserve CBM in winter and summer testing
- In light load examine variations in interchange transactions based on historical transactions.
  - Examine variations based on average historical LL interchange directly in generator deliverability testing (similar to status quo)
  - Condense historical interchange into 8 paths
    - Five external regions: North, West 1, West 2, South 1 and South 2 as defined in PJM CIL Study
    - All three Merchant Transmission Facility controllable tie lines

Proposed Modifications: External Interchange

- Justification for change to light load
  - Status quo light load approach applies historical tie line flow to individual zones bordering PJM directly in the base case.
    - Does not properly account for the external source/sink of the transaction and loop flow.
    - By not including this tie flow directly in the base case, this proposed change will not allow historical non-firm transactions to relieve future planning problems.
  - Condensing multiple external border regions to five large external regions is sufficient to capture a broad range of historical transactions for sensitivity analysis in planning studies.

Proposed Modifications: Internal Interchange

- Do not hold internal interchange between PJM regions at historical levels and instead allow the block dispatch approach to dictate the PJM light load and winter internal interchange.
- Ensure no area is exceeding its annual CETO plus a small margin in the base dispatch to account for generation ramping.
- Justification for change
  - Using historical internal interchange in a future planning model will not properly account for the rapidly evolving resource mix.
  - Using planning CETO levels has been a common practice in generator deliverability testing to ensure dispatch is not creating emergency conditions.

Proposed Modifications: Generator Ramping Changes

- Proposal 1: Individual Harmer deliverability requirements (aka resource ramping limits)
  - Wind and solar, storage, CIRs
- Proposal 2: Wind and solar Helpers
- Proposal 3: Facility Loading Adders
- Proposal 4: Eliminate EEFORd for resources < 50 MW
- Proposal 5: Upper limit for 50/50 Harmers and Facility Loading Adders
- Proposal 6: 50/50 Harmers
- Proposal 7: Individual facility deliverability requirements to account for energy-only MW
- Proposal 8: MISO wind

Proposed Modifications: Generator Ramping Proposal 1

- Wind and solar Harmers ramp up to the appropriate percentile historical output level for season/resource type/region.
- Percentiles based on 10 years historic and back cast data.
- The output levels associated with the percentiles will be periodically updated.
- Total Wind & Solar Harmer ramping capped at PJM online PGEN * PJM Avg EEFORd.
- Justification for change
  - More accurately reflects stressed dispatch conditions for each region and period under study
  - Improve operational flexibility to support evolving resource mix

Proposed Default Deliverability Requirements For Wind & Solar As % Nameplate

- Percentile illustration: The P90% for onshore wind during the summer in the MAAC region is 38%, which implies that during 10% of the peak summer hours onshore wind in wide areas across the MAAC region wind will likely be outputting more than 38% of their nameplate.
- Percentile weighting example: If region X is composed of two areas X1 and X2, where

Area	% of Nameplate	Nameplate (MW)
X1	40%	900
X2	60%	100

- Then the deliverability requirement level for region X is calculated as:

$$P = (40\% \times 900 + 60\% \times 100) / (900 + 100) = 42\%$$

Proposed Default Deliverability Requirements For Wind & Solar As % Nameplate

MAAC	Summer	Winter	LL (10AM-3PM)
Solar Fixed ($P_{80\%}$)	67%	*	78%
Solar Tracking ($P_{80\%}$)	89%	*	86%
Onshore Wind ($P_{90\%}$)	38%	73%	66%
Offshore Wind ($P_{80\%}$)	73%	96%	90%

PJM West	Summer	Winter	LL
Solar Fixed ($P_{80\%}$)	76%	*	82%
Solar Tracking ($P_{80\%}$)	84%	*	82%
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%	*	87%
Solar Tracking ($P_{80\%}$)	85%	*	85%
Onshore Wind ($P_{90\%}$)	45%	78%	71%
Offshore Wind ($P_{80\%}$)	68%	98%	93%

*** No generator ramping requirements**

Proposed Modifications: Generator Ramping Proposal 1

- Pumped Storage
  - Light load: No ramping
  - Summer & Winter: +100% CIRs
- Batteries (capability for “X” hours based on class duration)
  - Light load: +/- 100% MFO
  - Summer & Winter: +100% CIRs
- Wind & Solar: Per previous slide
- All other Generation Capacity Resources
  - Light load: No ramping
  - Summer & Winter: +100% CIRs

Proposed Modifications: Generator Ramping Proposal 1

- Hybrids will be studied using the appropriate ramping limit for each component of the hybrid and shall not exceed the MFO
  - Example: 100 MW MFO hybrid comprised of 100 MW fixed solar unit in MAAC with 40 MW CIRs and 50 MW MFO battery with 25 MW CIRs and can charge from grid.
    - Total CIRs = 65 MW
    - Scenario 1: For flowgate 1 during summer peak this hybrid is a Harmer. The solar unit will be modeled at 67 MW. The battery in discharge mode will be modeled at 25 MW. The total hybrid will be modeled at 92 MW.
    - Scenario 2: For flowgate 2 during light load this hybrid is a Helper. The solar unit will be modeled at 22 MW per Proposal 2. The battery in charge mode requires of -50 MW. The total hybrid will be modeled at -28 MW.

Proposed Modifications: Generator Ramping Proposal 1

- During summer generator deliverability testing, ramping limits are based on a unit's CIRs.
- For Capacity Resources where the CIRs are equal to the summer maximum facility output of the unit, or in the case of batteries their "X" hour rating, the ramping limit is 100% of the CIRs.
- For Capacity Resources where the CIRs are less than the maximum output, the ramping limit will be equal to the CIRs, except for wind and solar resources for which the ramping limit will determined through the following relationship.
  - Actual ramping limit = Actual CIRs * (Default ramping limit / Summer Capacity Factor) for the resource type and region (MAAC, PJM West, Dominion) in which it is located
  - For example, a 100 MW onshore wind farm with 13 MW CIRs, a summer capacity factor of 15% and a default ramping limit based upon the $P_{90\%}$ for onshore wind farms in the same region is 45%. The actual ramping limit would be 39%.

Proposed Modifications: Generator Ramping Proposal 2

- Wind and solar Helpers ramp down to 20th percentile historical output level for season/resource type/region.
- Percentiles based on 10 years historic and back cast data
- The output levels associated with the percentiles will be periodically updated.
- Justification for change
  - More closely matches a stressed dispatch that would be seen in operations rather than just maintaining average expected outputs on the receiving end of a constraint
  - Improve operational flexibility to support evolving resource mix

Proposed Availability Under Stressed Conditions For Wind & Solar As % Nameplate

MAAC	Summer $P_{20\%}$	Winter $P_{20\%}$	LL $P_{20\%}$ 10AM-3PM
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 $P_{20\%}$	LL $P_{20\%}$
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 $P_{20\%}$	LL $P_{20\%}$
Solar Fixed	35%	0%	32%
Solar Tracking	48%	0%	30%
Onshore Wind	0%	17%	8%
Offshore Wind	0%	13%	7%

Proposed Modifications: Generator Ramping Proposal 3

- Facility Loading Adders are offline units electrically just outside of the 50/50 dispatch and no longer include wind and solar resources, which are handled separately
- Facility Loading Adders modelled at base case setting for resource type instead of 85%
- Facility Loading Adders will only be considered in summer studies since this is where the extra generation may be required
- Justification for change
  - The use of the 85% level to model Facility Loading Adders was a legacy number carried over from the original summer peak generator deliverability test and is inappropriate for light load, winter and even summer where units are modelled at various output levels based on their resource type, load level and interchange.

Proposed Modifications: Generator Ramping Proposal 4

- Do not assign generators < 50 MW a EEFORd.
- Justification for change
  - With the proliferation of smaller units, larger units are often not being ramped to full output.

Proposed Modifications: Generator Ramping Proposal 5

- The total amount of online 50/50 and Facility Loading Adder generation will be limited to PJM online PGEN * PJM Avg EEFORd
- Justification for change
  - This metric attempts to restrict the ramping to an amount that may realistically be needed/occur during the period under study. Using PMAX does not make sense when many of the units are dispatched well below that level.

Proposed Modifications: Generator Ramping Proposal 6

- Establish similar procedures for single and common mode analysis
  - Instead of using 80/20 for single contingency ramping and 50/50 for common mode ramping use 50/50 for both.
    - Maintain status quo DFAX and impact thresholds for single contingency and common mode outages
  - Ramp generators to same output levels for both tests.
  - Energy-only portion of unit will be studied using separate individual plant deliverability procedure described in proposal 7.

Proposed Modifications: Generator Ramping Proposal 6

- Justification for change
  - With declining EEFORds the number of generators in the 80/20 excluding wind and solar now averages around 28, whereas the number of generators in the 50/50 averages around 12.
  - With removal of EEFORd for units less than 50 MW dispatches will be more concentrated with higher MW machines.
  - Also considering stressed wind and solar (Harmer and Helpers)
  - Change will allow the removal of operational contingencies and greatly simplify analysis by having a shared, common dispatch on which all contingency analysis is performed.

Proposed Modifications: Generator Ramping Proposal 7

- Establish individual facility deliverability for each generator and controllable MTF connected to PJM
  - Requires that each individual generating plant and controllable MTF be ramped to its maximum seasonal capability. Under these conditions the system must be secure for single and common mode contingencies.

Proposed Modifications: Generator Ramping Proposal 7

- Justification for change
  - While large numbers of variable resources will not be simultaneously tested at 100% MFO because of the negligible likelihood of such an occurrence, individual variable resources are much more likely to achieve such levels and should therefore individually be capable of full output in the base case to ensure their MFO is deliverable.
  - Removed energy-only MW testing from generator deliverability test
    - 1,600 MW non-wind and solar generation
    - 8,100 MW wind and solar generation
    - < 1,000 MW controllable MTFs

Proposed Modifications: Generator Ramping Proposal 8

- Do not modify MISO wind dispatch in base case, but instead use generator deliverability tool to ramp MISO wind to same value as PJM wind is ramped
- Consider MISO wind ramping in light load and winter using same ramping values for PJM onshore wind in the PJM West region
- Periodically review assumptions regarding external RTO wind and solar as increased penetration unfolds.
- Sink MISO wind to MISO North per MISO planning process
- Justification for change
  - Allows testing over a range of expected and extreme MISO wind levels