Additional Perspective on PJM Capacity Market Reforms

PJM Resource Adequacy Senior Task Force (RASTF)

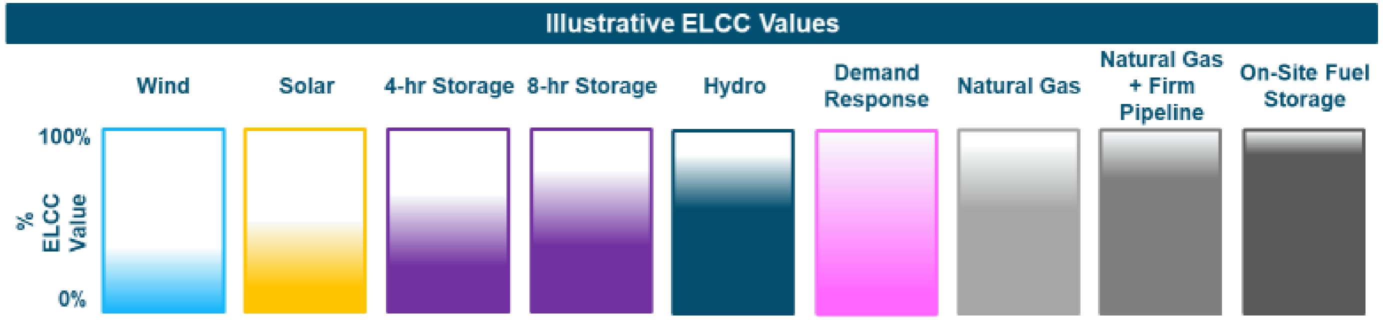
September 22, 2022

Energy+Environmental Economics

Zach Ming, Director

Refresh on Prior E3 Presentation

- **E3 on behalf of Calpine presented[1] to the RASTF on April 11, 2022 and provided three key recommendations for reforms to the PJM capacity market**
  1. **Extension of an ELCC framework to all resources (including thermal) and transition to a marginal ELCC framework**
     – This would more accurately capture key reliability risks including extreme weather correlated outages, fuel supply/security correlated outages, use limitations, and planned outages
  2. **Improvement to performance assessment to ensure resources are held accountable to their accredited capacity**
     – This could be accomplished through increased frequency/floor of performance assessment hours (PAH), removal of planned outage exemption, and measurement of performance relative to UCAP (i.e., balancing ratio = 100%)
  3. **Ensure market seller offer cap (MSOC) captures all costs of being a capacity resource**
     – Including cost of fully eliminating penalty risk and opportunity cost of foregone bonus payments
- *These recommendations are intended to be implemented together and not on a stand-alone basis; for example, it would not be appropriate to increase performance assessment threshold without updating MSOC to reflect those costs/risks*



[1] https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220411/item-2---e3-perspectives-on-capacity-market-reform.ashx

Evolution of Conversation in Interim

- **E3 and Calpine have continued to monitor the conversation to understand the perspective of other stakeholders and have taken away the following important points**
  1. Thermal risks are either inconsistently or not accounted for in today's accreditation approach
     - Request, from in particular AEE[1], that PJM study thermal risks due to natural correlated outage variability above UCAP, weather-dependent relationship of forced outages by generation type and sub-type, impact of fuel availability (location on pipeline, firm vs. non-firm contracts, on-site fuel availability), impact of planned outages, and ambient de-rates
  2. Thermal reliability risks are driven by both individual plant management decisions and exogenous factors
     - Concern, from in particular LS Power[2], that a class-based ELCC methodology cannot capture the diversity and complexity of thermal resources – it would simultaneously dilute accreditation of high performers and prop up accreditation of low performers
- **E3 and Calpine believe both of these points are valid and can be incorporated into tractable resource accreditation improvements under an ELCC for all paradigm**

[1] https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220715/item-04---aee-rastf-request-for-analyses.ashx
[2] https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220526/item-08a---reliability-risks-and-drivers---ls-power.ashx

Potential Approach

- **E3 proposes a modified ELCC for all framework that combines 1) class-based ELCC with 2) heuristic individual resource performance adjustments**
  - This is similar to the current PJM process for accrediting renewable resources and to thermal accreditation frameworks that have been proposed by Brattle in ISONE[1]
- **Class-based ELCC would appropriately reflect all plausible reliability risk in modeling framework**
  - Is necessary to capture 1) inherently infrequent events (e.g. polar vortex) and 2) expected forward-looking reliability risks (e.g. low wind events) that cannot be captured via a heuristic lookback
  - PJM would need to study appropriate class definitions – balancing accuracy with tractability
  - Should reflect fundamentals of reliability risks (i.e. directly modeling fuel supply constraints as opposed to historical probability of plants experiencing fuel related outage) and ensure that methods are both rigorous and understandable to stakeholders. There are multiple options for what risks to include – the simplest starting point would be ambient de-rates and asymmetric outage adjustments
- **Heuristic adjustment would *allocate* class-based ELCC to individual resources based on their actual recent performance**
  - Is necessary to differentiate resources based on performance factors related to management and send a signal that encourages optimal investments
  - PJM would need to develop a performance heuristic – evaluating performance during the tightest hours while ensuring sufficient sample size (could leverage LS proposal)

Class-Based ELCC

reflects systemic risks

Thermal > Zone > Tech Type

Sub Tech Type	ELCC
Non-firm fuel	60%
Firm pipeline contract	70%
On-site fuel storage (2 days)	80%
On-site fuel storage (10 days)	90%

Heuristic Adjustment

reflects individual unit performance

Individual Resource	Performance	Accreditation
Resource 1	65%	57%
Resource 2	75%	66%
Resource 3	85%	74%
Resource 4	95%	83%
	80%	70%

Final accreditation averages to class ELCC by allocating proportionally based in individual resource performance

[1] see "Empirical-Modeling Hybrid" https://www.mass.gov/doc/capacity-resource-accreditation-for-new-englands-clean-energy-transition-report-2/download

April 11 Presentation

Overview

- **E3 was retained by Calpine to review the current design of the PJM capacity market to evaluate its performance along several key objectives (shown right)**
- **E3 has identified:**
  - Several areas for market improvement
  - Several recommendations to better achieve key market design objectives

Key Market Design Objectives
1 **Reliability** Does the design support sufficient pricing to retain and/or incentivize new capacity to meet the long-run reliability standard?
2 **Cost** Does the design minimize the cost of capacity to society, subject to external constraints (such as clean energy standard)?
3 **Competition** Does the design fairly and non-discriminatorily compensate resources for the value they provide to the system?
4 **Implementable** Is the design tractable and understandable?

Areas for PJM Market Improvement

E3 has identified three key areas for market improvement

1. **Market is not appropriately valuing resources for their contribution to system reliability**
   - If the market does not consider all reliability risks, the system is less reliable than stated (artificial abundance)
   - If the market procures resources that do not provide the reliability they purport, customers bear costs without commensurate reliability benefits. Additionally, price suppression due to artificial abundance could drive existing resources out of the market and require costly new entry
   - If resources with different reliability benefits are valued identically, this creates inequity and stifles competition. Additionally, artificial abundance suppresses prices, impacting competition

Does not meet objectives of

- Reliability
- Cost
- Competition

2. **Market does not ensure resources are actually capable of performing consistently with their accredited reliability value**
   - Same reasons as #1 – a resource that cannot perform consistently with its accredited reliability value creates same issues as a resource that is not appropriately valued

Does not meet objectives of

- Reliability
- Cost
- Competition

3. **Market does not allow existing resources to bid full costs into market (go-forward + risk + opportunity costs)**
   - Over-mitigation of resources will cause existing resources to inefficiently exit the market, thus requiring new entry and increasing costs

Does not meet objectives of

- Cost

Key Recommendations

E3 has identified three key recommendations that correspond to the prior areas for market improvement

Each is described more fully in the rest of the presentation

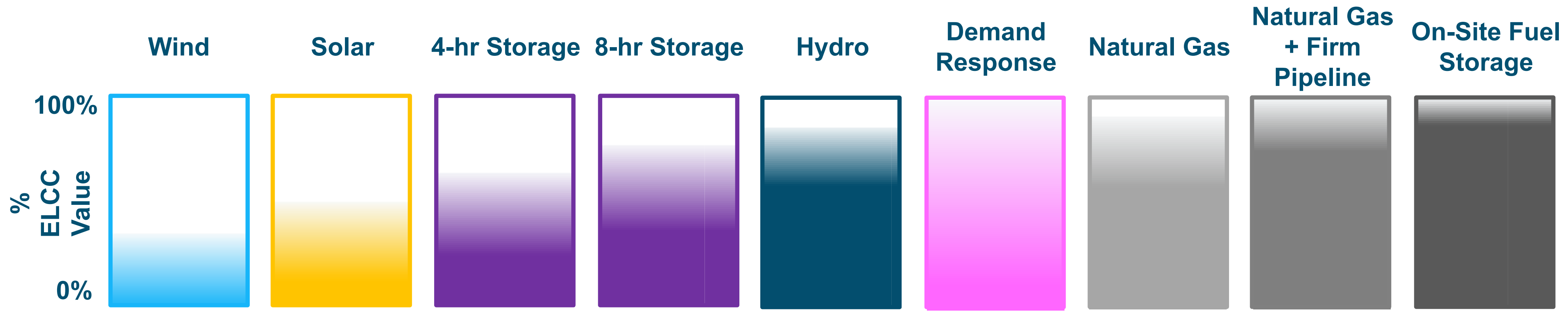
Timeframe	
	Key Recommendation 1: Use an ELCC framework for all resources in order to capture additional key reliability risks
Long-Term	• ELCC analysis should specifically be expanded to include: – Extreme weather correlated outages – Fuel supply/security correlated outages – Use limitations – Planned outages
Med-Term	• Transition from average to marginal ELCC
	Key Recommendation 2: Ensure performance assessment holds resources accountable to their accredited capacity
Med-Term	• Increase frequency of performance assessment hours (PAH) through a yearly PAH floor to ensure consistency with performance penalty price
Near-Term	• Remove planned outages as a performance assessment exemption
Near-Term	• Measure performance of resources relative to UCAP (i.e., balancing ratio = 100%) – This will reduce revenue neutrality feature of the current CP program and result in partial refund of capacity payments to load for underperforming resources
	Key Recommendation 3: Ensure market seller offer cap (MSOC) captures full costs of being a capacity resource
Near-Term	• Default MSOC should include a positive cost of fully eliminating penalty risk
Near-Term	• Default MSOC should be the higher of – ACR – E&AS + Penalty Performance Risk – Penalty Performance Risk + Opportunity Cost

If recommendations 2 is implemented, *recommendation 3 must be implemented as well* to ensure internal consistency

Key Recommendation 1: Use an ELCC framework for all resources to capture additional key reliability risks

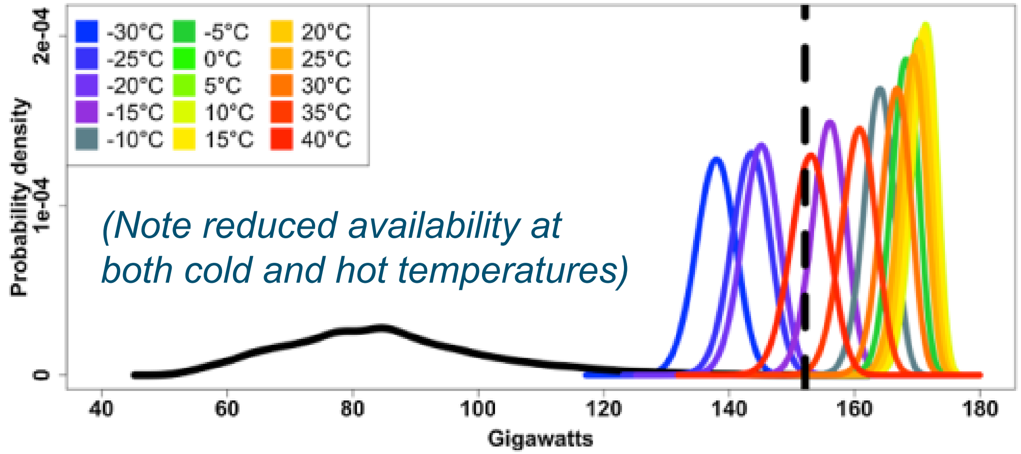
- **ELCC provides a technology-neutral mechanism to value full reliability risks across all resources on an apples-to-apples basis**
- **ELCC is already used in PJM to value wind, solar, storage, and hydro**
- **ELCC can be extended to thermal resources to capture four key additional factors**
  1) Extreme weather correlated outages
  2) Fuel supply/security correlated outages
  3) Use limitations
  4) Planned outages
     – Planned outages are already modeled in PJM loss-of-load-probability modeling and thus will inherently be captured in ELCC calculations
- **Factors 1-3 are described in the subsequent slides**

Illustrative ELCC Values

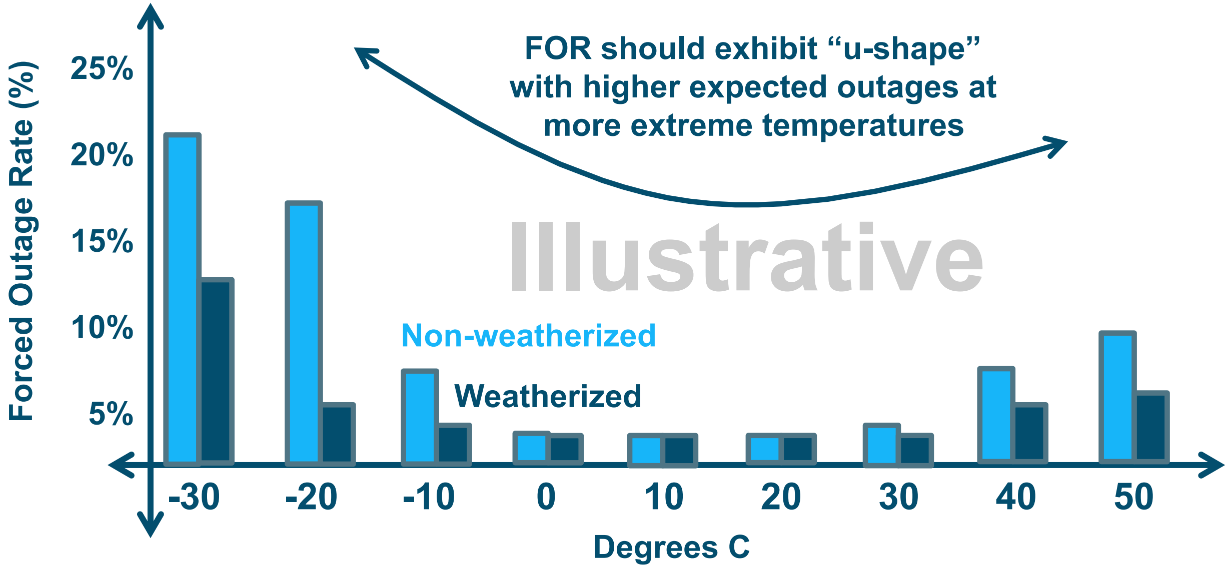


Extreme Weather Correlated Outages

- **PJM current approach to UCAP accreditation assumes outages are independent**
- **Research and experience has shown that availability of conventional generation is a function of temperature**
- **Accrediting conventional generating using an ELCC approach with a dynamic forced outage rate (FOR) that is a function of temperature can capture key correlated outage risk at extreme temperatures**
- **Dynamic FOR should account for key resource-specific differentiators, namely weatherization and other resiliency attributes**
  - PJM should conduct study and analyze historical data to develop dynamic FOR factors
- **Important to differentiate between resources with different characteristics (e.g. weatherized vs. non-weatherized)**



Source: *[Resource adequacy implications of temperature-dependent electric generator availability]*



Fuel Supply/Security Correlated Outages

- **Fuel supply/security is an emergent consideration in utility reliability planning, particularly as more resources (natural gas) have become more dependent upon "just in time" fuel**

- **Root causes of fuel supply/security can be accounted for in an ELCC resource accreditation framework**
  - Natural gas wellhead freeze-offs and pipeline constraints
    - ELCC framework can capture key systemic fuel supply risks by imposing additional "system-wide" forced outage rate to all exposed resources or "maximum output" from all exposed resources to capture the maximum gas deliverability capability during extreme weather conditions
  - Coal pile freeze-offs
    - Can be accounted for in correlated forced outages

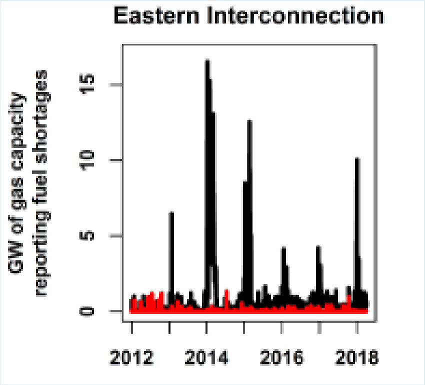
- **Resources with secure fuel supplies will be modeled as such**
  - On-site fuel storage
    - Highly secure supply of fuel that is resilient to nearly all fuel supply disruptions
  - Firm pipeline gas contracts
    - Significantly beneficial in systems with constrained gas pipelines during extreme winter weather (i.e. New England) but not resilient to natural gas wellhead freeze-offs (such as in Texas)

- **Incorporating fuel supply/security factors into a full ELCC modeling framework allows system planners to capture key interactive effects with other resources – for example it will have interactions with required levels of storage duration for full capacity value**

- **Acquiring rigorous information on fuel supply availability will be a key challenge**

In January 2014 Northeast cold snap, PJM experienced *9,300 MW (>13%of total operable fleet) of forced outages* due to natural gas shortages.

Plot shows sum of all unscheduled lack of fuel outages, de-ratings (partial outages) and startup failures at gas units.

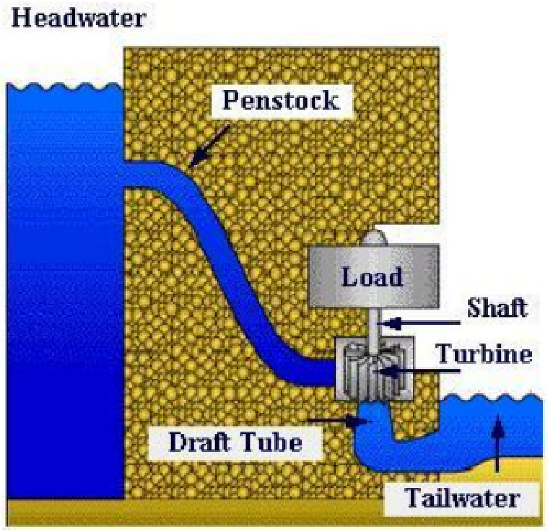


Black series: total outage magnitude
Overlaid red series: outage magnitude at gas plants that held *firm contracts* at the time of their failures.

Source: *What causes natural gas fuel shortages at U.S. power plants?*

Use Limitations

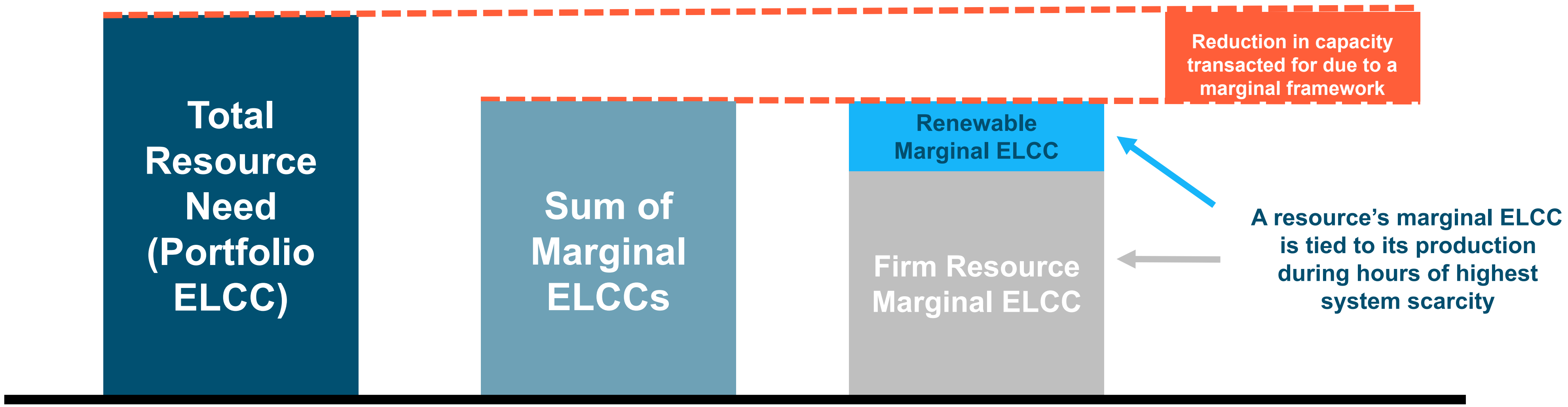
- **System planners have long considered resources with use limitations in reliability analysis, namely hydro**
  - A use-limited resource is one that is constrained by both maximum capacity output *and* energy generation
- **Many conventional resources are also use-limited or may increasingly become so**
  - **Local air pollution:** run-time limitations from resources in urban areas due to local air pollution restrictions may limit ELCC
  - **Carbon constraints:** A system with high clean energy targets or significant carbon constraints may limit energy generation from carbon-emitting resources
- **Extending existing ELCC hydro modeling techniques to carbon-emitting resources with use limitations should provide a robust estimate of capacity value for conventional generation**
- **Incorporating use limitations natural extends to a low or zero carbon system – a resource that cannot generate any energy will have zero ELCC**



http://encyclopedia.che.engin.umich.edu/Images/TransportStorage/Turbines/hyd-equ.JPG

Marginal ELCC

- **A marginal ELCC framework values resources based on their production during hours of highest system scarcity (i.e. peak net load not peak gross load)**
- **Transitioning from average ELCC to marginal ELCC will improve economic efficiency and incentivize the development of resources that decrease reliability costs**
  - Current PJM average ELCC approach uses the delta method – while E3 believes that the delta method is the best average method, marginal has advantages over average
- **A marginal ELCC framework will reduce the capacity procurement target (or equivalently provide a "free" resource of interactive effects**
  - Load benefits from a marginal ELCC framework since it does not have to procure as much capacity
- **Marginal ELCC accreditation is consistent with a capacity performance construct that assesses resource performance during the hours of highest system scarcity**



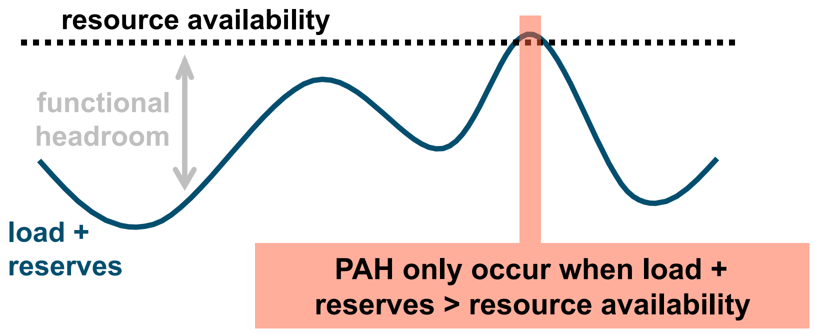
Key Recommendation 2: Ensure perf. assessment holds resources accountable to their accredited capacity

- **Ensuring resources perform in accordance with their accredited value requires a strong, consistent capacity performance (CP) construct**
- **Current frequency of performance assessment hours (PAH) is not significant enough recoup revenues from resources that do not / can not perform in accordance with their accredited capacity value**
  - Zero events in 2015-2017; 10 minutes of localized events in 2018; two hours in 2019
  - This is not wholly unexpected from a reliable system that is planed to a (better than) 1-in-10-year standard
- **E3 proposes three key reforms to the CP construct**
  1. Increase frequency of performance assessment hours (PAH) in order to ensure consistency with performance penalty price
  2. Remove planned outages as a performance assessment exemption
  3. Measure performance of resources relative to UCAP (i.e., balancing ratio = 100%)
     - This will reduce revenue neutrality feature of the current CP program and result in partial refund of capacity payments to load for underperforming resources
- **Proposals 1 and 3 are described in more detail in subsequent slides**

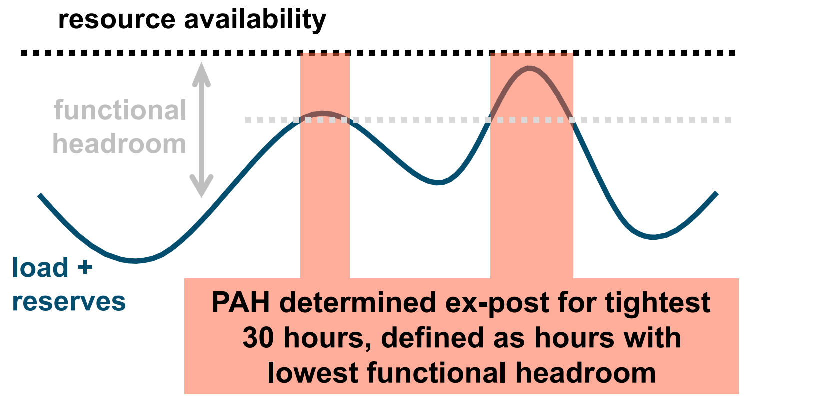
Increasing Frequency of PAH

- **PJM should increase the frequency and consistency of PAH in a manner consistent with capacity market framework**
  - Increasing frequency of PAH ensures annual exposure to penalties is consistent with annual revenues
  - Capacity market pricing is predicated on predictable, consistent compensation (opposite for example of energy scarcity pricing in other markets)
- **Threshold for PAH should be increased to target 30 hours per year based on functional head room**
  - *Difference between maximum and current output level of online resources + maximum of offline resources that can be started in a designated amount of time*[1]
  - By design, resource penalties and bonuses will need to be based on availability, not generation
- **PJM should ensure a floor of 30 PAH/year in order to provide stability and certainty in capacity market**
  - **Floor:** By end of year, if fewer than 30 hours fall within functional headroom threshold, PJM should determine on an ex-post the tightest 30 hours of the prior year and assess bonuses/penalties in these hours
  - **Additional PAH:** PAH can exceed 30 if there are more than 30 hours where functional headroom is less than the new threshold (scarcity hour)

Existing PAH Determination



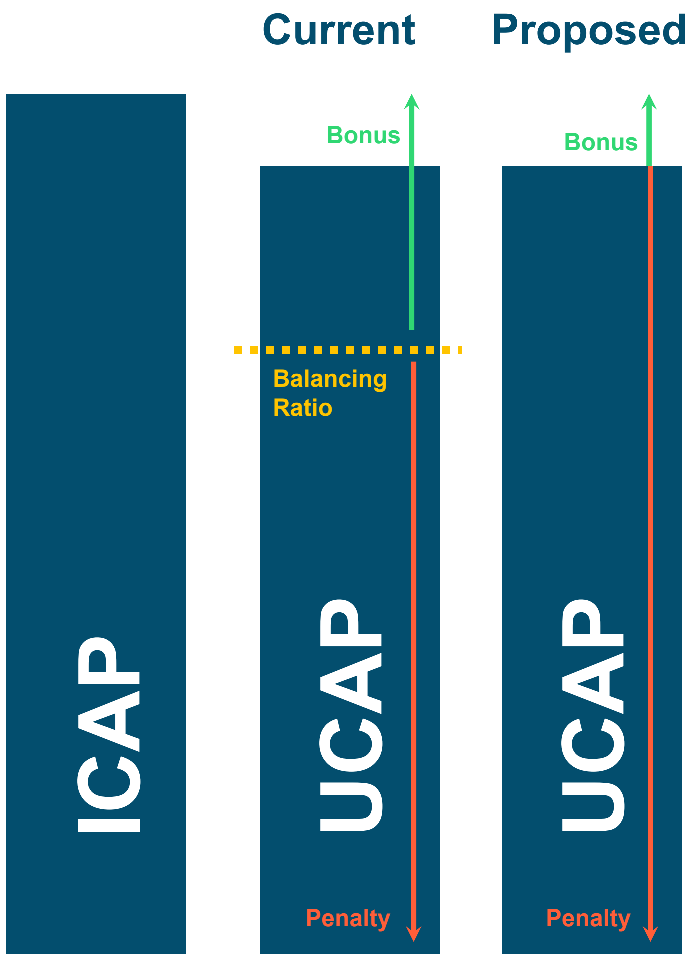
Proposed PAH Determination



[1] *Language from Potomac Economics comments on proposed MISO resource adequacy requirements, FERC Docket ER22-495-000*

Measure Performance Relative to UCAP by Eliminating Balancing Ratio

- **Current CP construct measures performance of a resource relative to its UCAP * Balancing Ratio**
  - Balancing ratio = total available capacity in the PAH / total committed capacity
  - The balancing ratio exists to send an economic signal to generate without imposing an aggregate cost on generators (all penalties from underperforming generators are paid to overperforming generators)
- **However, resources have sold their full UCAP to load and should be held accountable to deliver the full value of what they sold forward**
  - *Therefore, CP should measure performance relative to UCAP only*
- **This modification will remove the revenue neutrality aspect of the CP program and could likely result in aggregate penalty $ collections that can then be refunded to load (since they didn't receive the full capacity they paid for)**
- **Renewable and storage resources will be assessed relative to their marginal ELCC, which is consistent with their expected performance during scarcity hours**



Key Recommendation 3: Ensure market seller offer cap (MSOC) captures full costs of being a capacity resource

- **The current MSOC is based on gross avoidable cost rate (ACR) less energy and ancillary service (E&AS) net revenues**
  - Unit-specific ACR represents fixed annual costs that would not be incurred if a resource were not a capacity resource for a year less energy and ancillary service revenues
  - Adopted by FERC in Sep 2021
- **This is a departure from the prior MSOC that was based on the opportunity cost of foregone bonus payments associated with being a capacity resource**
  - Rationale is that the embedded assumption of 30 hours/year of performance assessment was higher than the actual number of expected hours, leading to complaints this MSOC was too high
  - Was ruled unjust and unreasonable by FERC in 2021
- **Resources with high expected E&AS net revenues cannot capture full costs of the risk and/or opportunity cost of being a capacity resource**
- **An MSOC that allows resources to bid full cost of risk and opportunity should be set as the highest of:**

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AFAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR + CPQR]

- Adjustment factor
- Avoidable Operations and Maintenance labor
- Avoidable Administrative Expenses
- Avoidable fuel availability expenses
- Avoidable maintenance expenses
- Avoidable variable expenses
- Avoidable taxes, fees, and insurance
- Avoidable carrying charges
- Avoidable corporate level expenses
- Capacity performance quantifiable risk
- Avoidable project investment recovery rate

https://www.pjm.com/-/media/committees-groups/committees/mic/2021/20210210/20210210-item-05d-tariff-attachment-dd-section-6-8-redline.ashx

$$\frac{Net\ CONE}{Penalty\ PAI} * \mathrm{B} * \mathrm{H} = \boldsymbol{Net\ CONE * B}$$

Proposed MSOC = Max (Gross ACR Including Risk – E&AS , Risk + Opportunity Cost[1])

- **It is expected that proposed changes to performance assessment construct will have significant impacts to the risks faced by a resource – it is critical that the MSOC adjust accordingly to reflect these risks**

[1]Assumes by convention cost of risk and opportunity cost are both positive values

Appendix

Interim Proposal While Thermal ELCC Is Developed

- **One interim solution while thermal ELCC is being implemented is a less complex heuristic that could closely approximate a resource's ability to avoid loss of load**
- **MISO has actively explored metrics to approximate availability during the tightest system hours, including:**
  - Available Capacity (ACAP) – shown to right
  - Seasonal Accredited Capacity (SAC) – shown below
- **"Tight" hours defined as margin (%) e.g. effective headroom**

Available Capacity (ACAP)

	Current Annual Construct	Initial Sub-annual Construct Proposal
Resource Accreditation	MISO accredits conventional resources annually based on a 3-year XEFORd excluding planned outages.	MISO will accredit by season based on resource's availability (ACAP) during the tightest operating conditions including planned outages and utilize a UCAP/ACAP conversion ratio to align PRM and accreditation.

Source: RAN Reliability Requirements and Sub-annual Construct

Seasonal Accredited Capacity (SAC)

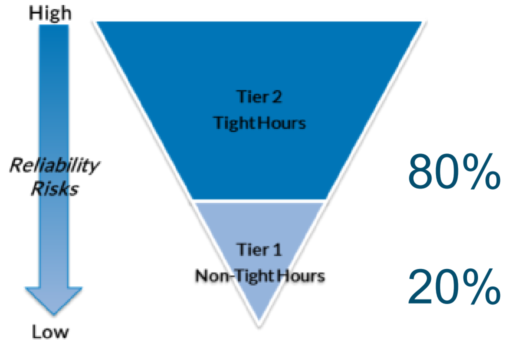
$$Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + offline\ margin\ (12\text{-}hour\ lead\ time)(MW)_j}{Real\ Time\ (RT)\ Load\ (MW)_j}$$; in which

$$Online\ margin\ (MW)_j = \sum\nolimits_{unit\ i\ in\ region\ j}(EmergencyMax_i - Energy\ MW_i - cleared\ operating\ reserve_i)$$

if a generation unit is online and under normal dispatch control

$$Offline\ margin\ (MW)_j = \sum\nolimits_{unit\ i\ in\ region\ j} Emergency\ Max_i - cleared\ offline\ supplemental\ reserve(MW)_j$$

if (i) a generation unit is offline; (ii) it's cold-start lead-time is less than or equal to 12 hours; and (iii) is not on outage



Balancing Ratio Numerical Examples

Overperforming Generator (Actual Performance > UCAP)

	Exemptions[1]	Balancing Ratio[2]	Bonus Rate $/MWh[3]	UCAP[4]	Actual Performance[5]	Total Bonus $/MW-yr[6]
Option 1: Status Quo	50%	70%	$1,700	90%	100%	$18,870
Option 2: Exemptions Excluded in Balancing Ratio	50%	85%	$3,400	90%	100%	$23,970
Option 3: Balancing Ratio = 100% (i.e. UCAP)	50%	100%	$3,400	90%	100%	$10,200

Key Takeaways

- A higher balancing ratio will cause an overperforming generator to benefit from a higher bonus rate but lower bonus MW
- Option 2: Will cause total bonus to increase if actual performance > UCAP (i.e. when higher bonus rate outweighs lower bonus MW) and vice versa
- Option 3: Will cause total bonus to increase if original balancing ratio is high (i.e. minimal reduction in bonus MW but high gains in bonus rate) and vice versa

Underperforming Generator

	Exemptions[1]	Balancing Ratio[2]	Penalty Rate $/MWh[3]	UCAP[4]	Actual Performance[5]	Total Penalty $/MW-yr[6]
Option 1: Status Quo	50%	70%	$3,400	90%	0%	$64,260
Option 2: Exemptions Excluded in Balancing Ratio	50%	85%	$3,400	90%	0%	$78,030
Option 3: Balancing Ratio = 100% (i.e. UCAP)	50%	100%	$3,400	90%	0%	$91,800

Key Takeaway

- A higher balancing ratio will always increase total penalties since penalty MW will increase but penalty rate is held constant

[1] Illustrative assumption
[2] Option 1 = illustrative assumption; Option 2 = 50% of balancing ratio reduction has been reduced (70% + [100%-70%*50%)]; Option 3 = 100% by definition
[3] Option 1 = $3,400 * (1 - Exemption %); Option 2 = $3,400 by design since balancing ratio has increased; Option 3 = $3,400 by definition
[4] Illustrative assumption
[5] Illustrative assumption
[6] (Actual Performance % – UCAP % * Balancing Ratio %) * $/MWh Bonus/Penalty Rate * 30 Performance Hrs/Yr = Total Bonus Penalty $/MW-yr

MSOC Numerical Examples

All units in $/kW-yr	Costs		Benefits					
Scenario	**Gross ACR**	**Risk**	**E&AS**	**Opportunity Cost**	**Net Revenues if doesn't clear capacity market**	**Net Revenues if clears capacity market**	**Required Minimum Capacity Bid**	
		Only applies if resource clears the capacity market		*Only applies if resource doesn't clear capacity market*	*Gross ACR + E&AS + Opportunity Cost*	*Gross ACR + E&AS + Risk*		
1: Low E&AS Low Opportunity Cost	($110)	($10)	$30	$0	($80)	($90)	$90	*Resource requires $90/kW-yr to clear capacity market or it will mothball/retire*
2: High E&AS Low Opportunity Cost	($110)	($10)	$130	$0	$20	$10	$10	*Resource requires $10/kW-yr to be as well off as if it didn't clear capacity market*
3: Low E&AS High Opportunity Cost	($110)	($10)	$30	$20	($60)	($90)	$90	*Resource requires $90/kW-yr to clear capacity market or it will mothball/retire*
4: High E&AS High Opportunity Cost	($110)	($10)	$130	$20	$40	$10	$30	*Resource requires $30/kW-yr to be as well off as if it didn't clear capacity market*

Risk Aversion

- **It is well established that risk-averse actors prefer a lower certain value to an uncertain higher expected value**
  - For example, someone might prefer guaranteed $40 above a 50% chance at $100
  - This is similar to saying that someone might prefer to pay $10 rather than face an uncertainty with 50% probability of losing $50 and 50% of making $50
- **The current CP construct is revenue neutral, which means all generators in aggregate have an expected value of $0, but with individual uncertain outcomes**
  - *Risk averse generators will pay to mitigate this risk*
  - Whether or not generators buy insurance to cover this risk is influenced by the price of insurance relative to how they value the risk themselves
- **The price of insurance is based on the broader market's willingness to take on non-diversifiable risk**