Market Seller Offer Cap (MSOC) Reform

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RASTF - February 28, 2022

Proposed Work Plan for 24/25 BRA Implementation

RASTF Meetings – MSOC Work Plan

- **Feb. 28**: Solution Options / Pkgs.
- **Mar. 7**: Solution Options / Pkgs. **(new half-day)**
- **Mar. 14**: Packages / Vote **(post-meeting)**
- **Mar. 24**: Final discussions, if needed

24/25 BRA
IMM Unit-Specific E&AS Posting

July 2022

24/25 BRA
Unit-Specific Offer Cap Reviews

Aug. – Oct. 2022

24/25 BRA
Offer Window

Dec. 2022

JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

2022

MRC & MC Meetings

- **Mar. 23**: MRC & MC First Read
- **Apr. 27**: MRC & MC Vote
- Next scheduled meetings are May 17 (MC) & May 25 (MRC)

FERC Filing & Order

- **By early May:** FERC 205 Filing
- **60 days for FERC review**

MSOC Overview

- MSOC is a price ceiling applied to certain capacity sell offers
  - Applied to existing generators of jointly-pivotal market sellers (i.e. those that fail the Three Pivotal Supplier (“TPS”) test, which typically all do)
- MSOC is based on Net Avoidable Cost Rate (“ACR”) formula defined in Tariff
- Net ACR = Gross ACR – Net E&AS Offset
  - **Gross ACR**: Incremental expenses required to operate the unit that an owner would not incur if such unit did not operate in the Delivery Year, including Capacity Performance Quantifiable Risk (“CPQR”)
    - Sellers may elect to use proxy default ACR values or go through unit-specific review
  - **Net E&AS Offset**: Unit-specific estimate of projected net revenues from energy and ancillary services markets in the Delivery Year

MSOC Objective / Principles

- Objective of capacity market power mitigation is to return the capacity market to outcomes that would prevail in a competitive market

- This requires mitigation of uncompetitive offers to competitive levels

- Competitive offer level includes all costs a competitive market seller would consider when making an offer; *reflects the level below which costs of accepting capacity obligation exceed benefits and seller would prefer not to clear*

Review of Concerns with Current MSOC Framework

- Inability to fully reflect costs and risks of taking on a capacity obligation
  - Not able to reflect any CP risk in certain scenarios (*example on slide 6)*
  - Not able to reflect opportunity costs related to CP (*example on slide 7)*
- Lack of clarity in rules and guidance on ability to consider avoidable costs consistent with retirement decision rather than “mothball” (i.e. not operate the unit for a year)
- Process issues and challenges with unit-specific reviews:
  - Ambiguity in what is allowed and what constitutes reasonable support for various ACR components, particularly CPQR
  - Timing issues (e.g. deadline for IMM to provide sellers E&AS offsets is after the deadline for market sellers to decide if a unit-specific review is needed)
  - Lack of transparency (e.g. E&AS offsets)
- Concern that the current “default” MSOC approach poorly balances (1) mitigating market power concerns, with (2) minimizing administrative burden and risk of over-mitigation

Illustrative Example #1: Inability to Reflect CP Risk in Certain Scenarios

Example (Gen A - 1 MW unit)

- Avoidable costs (excluding any CP risk): **$20** per MW-day
- Projected E&AS profits: **$50** per MW-day
- *Expected* CP penalty risk: **$10** per MW-day
  - Expected Availability during PAIs: 0.5
  - Expected Balancing Ratio: 0.8
  - Penalty Rate: $3,000 / MWh
  - Expected Hours of PAIs: 4
  - (0.8 MW – 0.5 MW) * $3,000 * 4 hours / 365 days = $10
- **Net ACR = -$20** per MW-day (effectively $0)

Issue

- Net ACR formula results in a $0 offer cap; prevents the market seller from reflecting their expected CP risk of $10 when taking on a capacity obligation
- Not consistent with minimum price a competitive seller would accept

Illustrative Example #2: Inability to Include CP Opportunity Cost

Example 2 (Gen B - 1 MW unit)

- Avoidable costs (excluding any CP risk): **$20** per MW-day
- Projected E&AS profits: **$20** per MW-day
- *Expected* CP penalty risk: **$0** per MW-day
  - Expected Availability during PAIs: 0.9
  - Expected Balancing Ratio: 0.9
- *Expected* CP Opportunity Cost: **$15** per MW-day
  - Expected Bonus Rate: $1,500 / MWh
  - Expected Hours of PAIs: 4
  - 0.9 MW * $1,500 * 4 hours / 365 = $15
- **Net ACR = $0** per MW-day (CP Opportunity Cost not considered in formula today)

CP Opportunity Cost

Intended to capture the expected bonus revenues that are foregone by taking on a CP obligation.

- A unit with no CP obligation earns more bonus revenues during PAIs than it would with a CP obligation.

Issue

- Seller expects to forego $15 in CP bonus payments if it clears and taking on a capacity obligation, but is unable to reflect that opportunity cost in the current Net ACR calculation
- A competitive seller would not give up those expected revenues for free

Ambiguity in Use of Retirement Avoidable Costs

- Lack of clarity in rules and guidance on what costs can be considered avoidable
  - Tariff Attachment DD Section 6.8(b)

    "…avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur <u>if such generating unit did not operate in the Delivery Year</u>…"
  - PJM Manual 18 Section 5.4.4 Sell Offer Caps

    "The avoidable cost calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the Open Access Transmission Tariff. The calculation should be based on the annual costs that would be avoidable <u>assuming the unit would otherwise retire</u>."
  - IMM ACR Template Instructions

    "…avoidable if the generating unit were to <u>not operate for the relevant Delivery Year but maintained in a state to place it back in service</u>"

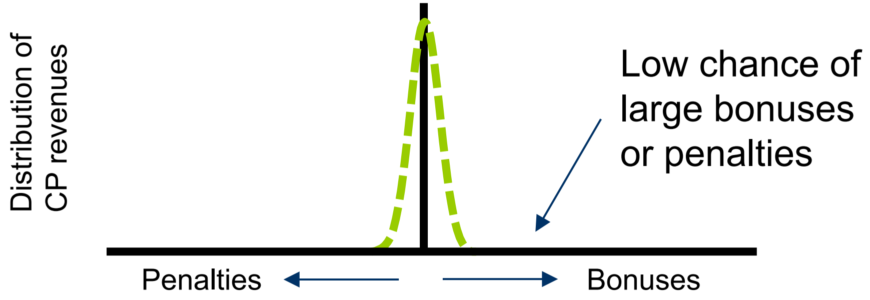
CPQR and Opportunity Costs

- Illustrative examples in prior slides on some of the issues used *expected* outcomes of CP penalties & opportunity costs
- Actual evaluations and considerations generally more complex
  - Beyond expected values, sellers are subject to and consider a range of potential CP penalty and bonuses for units
  - Approaches to valuing risk differ by company

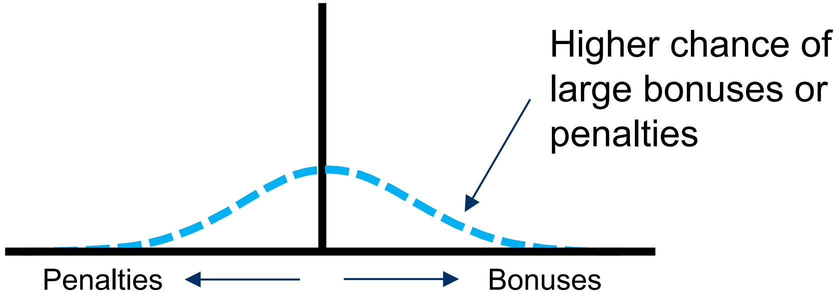
Illustrative CPQR Example

Competitive sellers are evaluating the capacity price at which they would be willing to accept capacity performance penalty risk. Suppose both of the following sellers envision a distribution of penalties and bonuses that on average cancel out such that the *expected value* of CP bonus plus penalties is zero

Seller 1
Has high accreditation reflecting *excellent expected performance* during PAIs



Seller 2
Has low accreditation reflecting *uncertain expected performance* during PAIs



- Neither seller would be willing to take on the risk for free nor could mitigate the risk for free.
- Both sellers would express a cost of accepting the risk in their offers, even if positive outcomes exactly offset negative outcomes *in expectation.*
- Seller 2 has a higher cost of risk (and cost of mitigating risk) and wishes to express higher offer price

Solution Option for Unit-Specific Offer Cap Calculation

Solution Option: Allow market sellers to reflect avoidable costs and revenues relative to those they would face given operating state absent clearing the market ("mothball" vs. retirement vs. "energy-only"), including applicable CP opportunity costs and risks

- "Mothball": shorthand for not operating the unit for the Delivery Year
- "Energy-only": shorthand for a Capacity Resource without a capacity commitment (e.g. does not clear in the auction)

Rationale:

- Consistent with intent to allow MSOC to reflect the price a competitive seller would offer (given their particular decision at hand)
- Addresses issue where CP risk is not able to be reflected in the offer cap by allowing sellers to include incremental costs of taking on Capacity Obligation relative to being "energy-only"
- Addresses issue of CP Opportunity Costs not being included in formula
- Addresses ambiguity in "mothball" vs. retirement avoidable costs

Solution Options (Design comp. 6a, 6c, and 7: Process timing and approvals)

- Move IMM deadline to provide unit-specific E&AS offsets to 150 days prior to the auction for preliminary values & 135 days prior for final values
  - The current deadline of 90 days is after the deadline for market sellers to elect a unit-specific review (120 days prior)
- Shorten time between the IMM deadline to provide unit-specific offer caps & market seller's deadline to agree or disagree with caps from 10 days to 5 days
  - Provides an earlier indication to PJM of disagreements to increase the time to work with market sellers on those disagreements
- Change PJM determination from a simple accept or reject to allow for approval of alternative values based on review and discussions with market sellers

Solution Options for Unit-Specific Review Process(cont'd)

Solution Options (Design comp. 8: Transparency of models, methodology, etc.)

- Publish a document that further describes the calculation and inputs of the net E&AS offset values provided to market sellers

- Provide or allow market sellers to request details of the E&AS offset results to better understand the final number (e.g. run hours, total gross revenues, etc.)

- If rejecting a market seller's requested offer cap, provide the Gross ACR template that supports the IMM or PJM approved offer cap value

Solution Options for Unit-Specific Review Process(cont'd)

Solution Options (Design comp. 9 and 10: Guidance for Supporting Documentation)

- CPQR Guidance:
  - Publish a guidance document for market sellers that further details acceptable methods of supporting the costs of CP risk
  - Provide a standardized CPQR approach that sellers could opt-in to use, along with guidance on reasonable inputs into the model

- Fixed vs. Variable Cost Guidance:
  - Publish further guidance on how market sellers can provide reasonable support that the costs going into the ACR calculation do not include those allowable in energy market cost offers

Solution Options for Default Market Seller Offer Cap

Solution Options **(Design comp. 11: Default MSOC methodology)**

- Default MSOC based on average of prior three BRA clearing prices, discounted by some factor (e.g. 5 or 10 percent)
  - Could be determined for just the RTO or certain LDAs as well
- Other alternatives might include a default MSOC based on:
  - A design mirrored after ISO-NE's that considers auction results from the prior auction, along with expected changes in demand for the upcoming auction
  - CP opportunity costs that reflect expected bonus rates, hours of PAIs, etc.

Contact

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