Comprehensive Market Design Stakeholder Comment Matrix
Design Working Group *FINAL*

The AESO is requesting written feedback from the Capacity Market Design Working Group (DWG) members about the content of the first draft Comprehensive Market Design (CMD 1) and about the working group session in which CMD 1 was discussed. This draft comment matrix is provided in advance to help working group members prepare for their upcoming session. Following the working group session, the AESO will post a **final comment matrix** one (1) day after the session. This final comment matrix should be completed by working group members within four (4) business days. The final feedback matrix is intended for working group members to provide written feedback about CMD 1 or the content of their working group session that is within the scope of their working group.

The AESO will post all comment matrices and any other feedback received from working group members on www.aeso.ca and on the Capacity Market SharePoint site. **Please note that the names of the parties submitting each completed comment matrix will be included in this posting.** The AESO does not intend to respond to individual submissions.

If you have any questions about this comment matrix, please email capacitymarket@aeso.ca

Name: Todd Cole Organization: MEG Energy.

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CMD Key Design Questions	Comments and / or Recommendations
1. UCAP: Can you support using Availability factor for dispatchable resources? Does the approach meet the intent of a resource neutral approach to capacity volume that reflects the deliverability of energy during periods of tight system conditions?	The fundamental purpose of the capacity market is to ensure reliability by creating an attractive and sustainable investment climate for existing and new generation. To meet this goal transparent, stable, predictable and 'bankable' capacity payments, that are fully aligned with a penalty and incentive assessment, are essential. **Definition of "available"** Need to clarify that *availability* means a resource is available to receive and respond to a dispatch in real-time, *i.e.* within the delivery hour. It is important that the UCAP considers energy that is available for dispatch in real-time and not simply declared AC.may These two values will not be the same for long lead time units. The definition of "available" used in the UCAP calculation should be the same definition used in the unavailability penalty period. **Availability factor** MEG supports the use of availability factors where possible and basing the calculation of UCAP on the average availability in the 100 hours with the tightest supply cushion. **Availability factor for net-to-grid self-suppliers** MEG specifically notes that an availability factor should also be used for net-to-grid/self-supplied. Net-to-grid facilities are not always price-takers in all blocks. Accordingly, net-to-grid facilities may have un-dispatched energy available in low priced hours. Assessing UCAP for net-to-grid facilities based on a capacity factor may lead to inefficient outcomes (loss of productive efficiency) as some net-to-grid blocks may have high variable costs or high opportunity costs. The UCAP calculation should not distort offer behavior or create an incentive for more facilities to behave as price takers. Instead, the UCAP formula should be designed to accurately reflect the expectation of an assets ability to deliver during the tightest supply cushion hours of the delivery year. In the

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	case of net-to-grid facilities, this requires consideration of the un-dispatched blocks that were available for dispatch in real-time had the energy price risen to the level of those offers. **UCAP determination for new net-to-grid self-supplied facilities** MEG suggests that net-to-grid facilities should be able to state their own UCAP in the first year as each facility is unique. **UCAP adjustments** MEG supports a process that allows for UCAP adjustments based on material issues that should not reasonably impact future years. MEG agrees with the AESO that there should not be any exemptions for the purposes of penalties. It is important to promote efficient maintenance timing through a penalty and incentive structure. It may be extremely punitive to a resource's annual revenue if a one-off event lowers the 100-hour average of an asset for a single year resulting in a lower UCAP and capacity revenues for the following five years. UCAP adjustments may be particularly important in the first few years as prior to the implementation of the capacity market, participant behavior was based on the incentives that existed at the time. For example, importers weren't motivated to be available in hours where the supply cushion was low, but the pool price remained below $20, such as in 2017. **Asset substitution** Given the proposed UCAP calculation based on the 100 tightest hours of supply cushion combined with the availability penalties, asset substitution is not needed and is in general will no longer hold much value. Participants will only have UCAP that they are willing to sell to another participant if the AESO has incorrectly calculated their UCAP such that it is easy for the asset to over perform, an unlikely situation. Asset substitution for large players to trade obligations back and forth between owned resources should not be allowed. Asset substitution with this benefit does not allow for a level playing field as large participants will essentially have penalties assessed against their entire portfolio, allowing them to smooth risk in a way that smaller participants are unable to.

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2. Payment Adjustment Mechanism: Can you support using a 60/40 performance/ availability framework? Does the approach achieve the intent of higher adjustments to performance periods?	**<u>Unavailability payment adjustments</u>** MEG in general supports the inclusion of an unavailability framework but suggests a clear delineation between high and low incentive/penalty hours and a higher weighting for unavailability payment adjustments is suggested. Consistent with its comments and detailed submissions prior in response to SAM 3.0, MEG notes that penalties assessed only during EEA events create a significant risk for generators. This risk becomes more manageable when spread over a larger number of hours. The unavailability penalty, which considers average performance over the tightest 100 supply cushion hours relative to committed capacity, is an effective tool for mitigating this risk. The alignment between 100 tightest supply cushion hours in both the UCAP calculation and the unavailability calculation will provide generators confidence that they are able to deliver on their capacity obligation. A to shift a greater percentage the penalty weighting (i.e. 60%) to the unavailability penalties would provide a more symmetrical opportunity to avoid penalties. The most significant issue with the availability adjustment framework is the imbalance between penalties and incentives. In CMD1 generators only receive penalties, *i.e.* over performance is not rewarded. This creates a systematic risk in the market. For example, consider two separate facilities each with 100 MW of UCAP. If one unit delivers 90 MW of UCAP (due to a maintenance period during a scarcity event for example) and the other delivers 110 MW. The net delivery from the pair is 200 MW which the market expected, however, due to the lack of symmetry in the penalty and incentive framework, penalties of about 5.2 MW would result despite performance to the market meeting expectations. Without an incentive system to balance penalties the generators will need to anticipate the risk of lower revenues. Generators may price the risk of receiving penalties into their capacity market offers. As the EEA performance penalties are likely to be assessed over very few hours (and possibly even a single event in a year) this creates significant risk that the generator could lose a sizable portion of its capacity payment if it missed its delivery obligation. It is possible that that generator will have no ability to recoup the penalty if another EEA event does not occur in that year. Overall the risk may translate directly to higher capacity price offers and higher costs for consumers. -without any higher reliability expectations to the market

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	<u>Design of payment adjustment formulas</u> The inclusion of "expected EEA hours" in the non-performance penalty formula creates fairness issues. The design of the formulas[1] seems to suggest that a generator could lose up to 78% of their annual revenue during EEA events and up to 52% of their annual revenue during the 100 tightest hours. Generators could be penalized at double the rate intended if twice as many EEA hours actually occur than expected. If there are less EEA hours than expected, a generator could be at risk for 130% of its annual value during very few events. If there are no EEA hours, and generator that was never dispatched would be penalized less than less than 100% of its capacity revenue – creating a free rider issue. **<u>Incentive payments</u>** MEG supports the AESO's decision to include incentive payments in the EEA performance periods and proposes that the availability periods also include incentive payments to incent additional energy from supply resources, which may also prevent an EEA event. The UCAP events will fluctuate slightly from year to year and, accordingly, the AESO should also expect generators availability performance to fluctuate slightly from year to year. One solution to this problem is to provide incentive payments. Another solution may be to use a threshold-based system, like the AESO's current proposal on UCAP adjustments during rebalancing auctions, such that within a small band around the UCAP providers will not be penalized for under-performance. A revenue neutral incentive/penalty scheme that is aligned with the UCAP calculation may result in a generator expecting to be net zero from an incentive/penalty perspective, which leads to more predictable, stable and *bankable* capacity revenues for investors resulting in increased reliability for consumers.

[1] the unavailability payment adjustment rate is designed as 40% * 1.3 and the non-performance payment adjustment rate is designed as 60% * 1.3,

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	<u>Outage exemptions</u> Outages should not be directed by the AESO through approval or exemption, or de-facto by the approval/exemption of outages for other generating assets. The exemption of outages by the AESO would create a system where larger incumbent generators create a risk for smaller generators. MEG is opposed the AESO approving outages; MEG supports the continued use of the current system whereby generators advise the AESO of planned otuages. **<u>Balance of penalties and incentives</u>** MEG suggests an annual incentive cap as a fraction of capacity market revenue per MW to accompany the penalty cap as a multiple of revenue. It is not desired for generation resources to withhold capacity from the capacity auction knowing that they can earn more through incentives without having the risks that comes with committing capacity., Given the complexity of the market and the potential for unintended consequences it is suggested penalties be phased in over several years to ensure the framework operates as expected.
3. Payment Adjustment Mechanism: Can you support a monthly cap at 300%? Does the approach achieve the intent of reasonably limiting adjustment payments?	MEG would support a monthly settlement cap at perhaps 150% rather than a monthly cap to protect generators from cash flow issues.
4. Payment Adjustment Mechanism: Can you support a 1.3x annual revenue/ rebalancing assessment limit? Does the approach achieve the intent of ensuring capacity resources are available for the obligation period?	Yes, MEG supports1.3x annual revenue/ rebalancing assessment limit. It strikes a balance between incenting performance and limiting annual risk of losses. It is important to have a reasonable annual penalty cap to encourage participation in the capacity market by limiting risks to a manageable range and yet it is also important to have high enough penalties such that they send a message and incent proper behavior.

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5. Market Power Mitigation: Can you support setting a market power screen as a fixed percentage of aggregate UCAP requirement for the auction? Does the approach meet the needs of mitigating supplier market power?	MEG supports this this principled approach given that it only mitigates market participants that have a large enough portfolio to exercise market power. This minimizes the administrative burden while protecting load from market power.
6. Market Power Mitigation: Is a price cap of 50% of net CONE appropriate to mitigate the offers of suppliers with market power?	While MEG supports the use of a price cap as an ex-ante mitigation measure, applied only to participants who have market power, the 0.5 x net-CONE may be too low. Mitigation shouldn't push offers below competitive levels and net-CONE is the competitive outcome. Therefore, the market power mitigation cap should be set at 1 x net-CONE, allowing competition to set the correct price and further ensuring existing generators the opportunity to earn a fair return which in turn aligns with the principles of FEOC in the market In other markets the offer cap for mitigated resources is often below net-CONE because the market is expected to clear with a new entrant setting the price. This approach may be problematic in Alberta given its small size. It can be expected that Alberta will have many years where no new capacity is purchased and existing generation will need to set prices at a level that allows them to recover a fair return on their fixed costs.
7. Market Power Mitigation: Do you think there is sufficient support that mitigation of buyer side market power is not initially required in the capacity market?	This question requires clarification and discussion.
8. Delisting: Are there some circumstances where the delist bid of an asset does not clear but the asset continues to participate in the energy market?	MEG supports this flexibility for market participants. Should not be allowed to extort market power and this should be monitored.
9. Delisting: Should a resource be able to delist from the capacity market but be eligible to participate in the energy and ancillary services market? For example: a. An asset of a non-mitigated supplier fails to clear, should it be allowed to continue energy market participation?	MEG supports this flexibility for market participants. De-listing should require sufficient notice and transparency as to the nature of the delisting so that the market can adjust.

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b. For long outage requirements that are for a substantial portion of the year?	
10. Transition to Capacity Market: Is a rebalancing auction for first obligation period 2021/22 required and practical?	MEG would agree that rebalancing is desired for the first auction. The AESO and market participants have generally agreed that a rebalancing auction should occur 3-months in advance of each delivery year. If the AESO is not amenable to holding a 3-month rebalancing auction for the first delivery year one alternate solution is to not penalize generators in the first delivery year.

General Comments

Retirements

MEG does not support the AESO's current proposal that retirement requires a resource "to demonstrate that the net going-forward costs of maintaining the resource in operational status at the current capacity level exceeds revenues that can be earned in the capacity market." Resource development and retirement decisions should be made by shareholders who bear the risk and reward of investment.

Resources should be entitled to the opportunity to earn a fair rate of return on their assets, not simply enough to cover maintenance, and resources should be able to retire for reasons outside of the electricity industry (i.e. a self-supplier is retiring its load and wants to shut down the whole facility). Further, if a market participant doesn't have market power then the AESO should not be concerned about retirement choices. For all retirements that occur prior to the base auction, market power should not be a concern. Given a three year forward period there should be numerous projects that could be developed in response to retirements.

MEG would support more stringent rules on mothballing as mothballing may raise prices while continuing to discourage a new entry.

Rebalancing Auctions

At the general session, the AESO noted it is considering a threshold-based change where an adjustment less than a certain level would not require rebalancing. MEG supports this approach.