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: The Cogeneration Working Group **Organization:** The CWG, as represented by Power Advisory LLC, is comprised of the following members: (1) TransCanada; (2) Suncor; (3) Cenovus; (4) Canadian Natural (CNRL); (5) Dow (6) Imperial; (7) MEG Energy; (8) Husky; (9) Nova Chemicals Corporation; (10) Syncrude; (11) Lafarge; and (12) InterPipeline.

Date: February 27, 2018

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 maintain 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 the penalty and incentive assessment, are essential. **Definition of "available"** At the outset, the CWG wishes to confirm that *availability* means that 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. These two values will not be the same for long lead time units. The definition of "available" used in the UCAP calculation must be the same definition used in the unavailability penalty period. Please see the response to question 2 below for support of the CWG position that the definition of availability to be "available for dispatch in real-time". **Availability factor** The CWG 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. Given that the AESO is procuring capacity to meet a specific reliability goal it is ideal to assess UCAP during the hours that matter most for reliability. Further, given the AESO's intention to assess penalties during the 100 hours with the tightest supply cushion, setting UCAP in this manner aligns the product being sold with the product being measured and assessed for penalties. This provides generators with confidence that they will be able to deliver on their obligations. **Availability factor for net-to-grid self-suppliers** The CWG specifically notes that an availability factor should also be used for net-to-grid/self-supplied assets where appropriate. Net-to-grid facilities are not always price-takers in all blocks. Accordingly, net-to-grid facilities will often have un-dispatched energy available in low priced hours. If there is in fact un-dispatched capacity available this capacity should not be treated differently than

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	a thermal asset that has priced one or more of its energy offer blocks higher in the merit order. Assessing UCAP for net-to-grid facilities based on a capacity factor may create the incentive for net-to-grid facilities to become price-takers on all blocks in all hours to ensure higher revenue in the capacity market. This would 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 energy during the tightest supply cushion hours of the delivery year. In the 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** The CWG understands from the market design working group session that the AESO intends to develop a process for determining UCAP for new net-to-grid facilities with CMD 2.0. The CWG would suggest that a net-to-grid facility should be able to state its own UCAP in the first year as it will not be able to use an average of similar facilities as has been proposed for new renewable facilities, given that there simply are no similar facilities. The penalty structure will incent the net-to-grid facility to sell as much capacity as it is able to deliver and no more. The net-to-grid facility is in the best position to know its capabilities moving into the first year due to the uniqueness of each facility. **UCAP adjustments** The CWG 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 the penalty and incentive structure. However, 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. Therefore, the CWG supports a process that allows for UCAP adjustments based on material issues that should not reasonably impact future years, such as force majeure events. This type of allowance is 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. If this reality is ignored it would result in a lower UCAP than if calculated after the capacity market was implemented. The CWG would note that if the penalty scheme is designed in a reasonable manner, generators will be motivated to choose the right UCAP and not to overinflate their commitment.

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	<u>Asset substitution</u> Given the proposed UCAP calculation based on the 100 tightest hours of supply cushion combined with the availability penalties, asset substitution in general will no longer hold much value. This is because participants will need to perform throughout the year and their UCAP has already been calculated based on expected delivery. 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 uncleared capacity. As such, asset substitution has limited value in the current framework. With the structure the AESO has proposed, it is essential that incentives are paid within the performance adjustment framework. This allows participants to manage year to year variation in UCAP within a balanced penalty and incentive scheme and does not simply create an undue risk as with the current proposal.
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>** The CWG 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 would be appropriate. Consistent with its comments and detailed submissions prior to and in response to SAM 3.0, the CWG notes that penalties assessed only during EEA events create a significant level of 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. That being said, the CWG would propose to shift a greater percentage the penalty weighting (i.e. 60%) to the unavailability penalties to provide a more symmetrical risk management framework. In addition, the most significant issue with the availability adjustment framework is the imbalance between penalties and incentives. Generators can only receive penalties, *i.e.* over performance is not rewarded. This creates a systematic and unbalanced risk in the market. For example, consider two units each with 100 MW of UCAP. If one unit delivers 90 MW of UCAP in a year and the other 110 MW (due to scheduled maintenance cycles for example), the net delivery from the pair is 200 MW. Notably 200 MW is what customers have paid for in terms of total UCAP. However, due to the lack of symmetry in the penalty and incentive framework, penalties of about 5.2 MW would result despite performance being in line with expectations. Based on a preliminary analysis of the year over year volatility in individual asset UCAP values, it appears this risk amounts to

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	something in the range of $50M for the generation fleet. It is important to note that this cost will accrue to generators even when they perform exactly as expected on average. Therefore, without incentives to balance penalties the risk will be exceptionally difficult to manage. Generators will 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 in a single event in a given year this creates significant risk that the generator could lose a large portion of its capacity payment if it missed its delivery obligations in a single assessment period. Further, there is the possibility that that generator will have no ability to recoup their payment if another EEA event doesn't occur in that year. This high risk will translate directly to higher capacity price offers and higher costs for consumers. This higher cost to consumers will not result in higher reliability but will simply reflect the high-risk market design. **<u>Definition of “available”</u>** As noted in response to question 1, the CWG suggests that in order to be “available” a unit must be “available for dispatch in real-time.” This definition should apply equally to the UCAP calculation and the unavailability payment adjustment calculation. Further, it is important that the payment adjustments reflect actual contributions to system reliability. Units that do not deliver capacity should expect to not be paid for that capacity with 100% certainty, and in general should expect some penalty in addition for non-delivery. If a resource with a capacity obligation supplies 0 MW of capacity for a year to the real-time market, it has essentially free-ridden on reliability provided by other participants. The penalty and incentive mechanism should preclude this possibility. **<u>Design of the payment adjustment formulas</u>** The CWG notes that the inclusion of “expected EEA hours” in the non-performance penalty formula creates significant issues. The design of the formulas[1] seem to suggest that it is the AESO’s intention 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. However, if for example, the AESO expects three EEA hours within a year and sets the penalties accordingly but during the delivery year six EEA hours occur,

[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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	capacity providers will be penalized at double the rate intended. The inclusion of “expected EEA hours” in the denominator of the non-performance payment adjustment rate means that a capacity provider could be at risk for 130% of its annual revenue in years where the AESO expects fewer EEA hours than actually occur. Conversely, in years where there are fewer EEA hours than expected (or none at all), a capacity provider that was never available to be dispatched, would be penalized less than less than 100% of its capacity revenue – creating a free rider issue. **<u>Incentive payments</u>** The CWG supports the AESO’s decision to include incentive payments during the EEA performance periods. The CWG also proposes that the availability periods include incentive payments to incent additional energy from supply resources, which may prevent an EEA event. Currently, the design of the unavailability payment adjustment allows generators to average out within a delivery year, but not across delivery years. As a result, a generator could under deliver on its availability in one year by 5% and over deliver in the subsequent four years by 2-10% each and yet that generator would have paid penalties in the first year without any ability to even out over time. The UCAP 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. The current asymmetry has the negative side effect that, on average, a generator has to expect to be net penalized, *i.e.* it has to effectively discount its capacity revenue. This will lead to higher capacity prices in the market not only to compensate for the expected penalties but also for the increased risk. A revenue neutral incentive/penalty scheme on the other hand that is aligned with the UCAP calculation results 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. **<u>Outage exemptions</u>** The CWG 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 the penalty and incentive structure. The CWG considers that the outage concerns of some market participants can be largely solved by allowing incentive payments during the unavailability periods. In this way, generators will pay penalties in some years but receive incentives in other years. The ability to smooth the risk over years, rather than needing to succeed in each individual year, lowers risk to generators. In addition, the provision of exemptions would pre-suppose a form of actual, or tacit, AESO approval for outages. As generators

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	with complex industrial processes behind the meter, co-generators will have many considerations for the timing of maintenance and planned outages. However, the timing of such 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 CWG believes that the exemption of outages by the AESO would create a system where larger incumbent generators move risk to smaller generators, or generators with extenuating and complex operational considerations behind the meter, in effect dictating the timing of outages for the entire market. For these reasons, the CWG is strongly opposed to the exemption of outages from penalties and also to the AESO approving outages. **<u>Balance of penalties and incentives</u>** The CWG notes that penalties should at a minimum claw back 100% of payments for non-delivery while incentives should be less than the expected value of forward capacity sales. To do otherwise would create perverse incentives. Resources should not be able to make some money from the capacity market even in a situation where they never turn on, as would be the case under the current penalty structure in a year without EEA events. Likewise, resources that withhold capacity from the capacity auction knowing that they can earn more through incentives without having the risks that come with committing capacity should not expect to be paid more than a committed resource. **<u>CWG Proposed Solution</u>** A simple solution for penalties and incentives is preferred. The AESO should: 1. Fix the number of hours in the non-performance adjustment to a reasonable number (*i.e.* 30 hours) and simply set a fixed $/MWh penalty for non-delivery during EEA hours. 2. Continue with the revenue neutral approach by paying performance incentives from the penalty pool. Note that non-performance during EEA hours is already captured in the unavailability adjustment hours suggesting that any additional non-performance adjustment does not need to be large. 3. Charge a non-delivery payment adjustment against the availability target, *i.e.* if a unit is short of its availability target on an annual basis it pays a multiple of the capacity price per MW (for example 1.1x). In effect, if a unit with a 100 MW capacity commitment delivers 90 MW on average during the 100 hours, it will have 11 MW of capacity penalties. 4. Pay an over delivery incentive set at a fraction of the capacity price per MW. 5. If there is excess value from under-delivery penalties relative to over-delivery incentives refund the difference to consumers. If there is a shortage reduce the incentive to be revenue neutral.

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	This solution creates the following benefits: 1. Strong incentives to deliver during emergencies 2. Retains the incentive to sell the forward capacity commitment as incentives are less than the clearing price 3. Allows units to manage annual variation in UCAP by earning incentives in years with higher availability 4. Refunds customers if the overall system delivery of capacity falls short of the commitment Given the complexity of the market and the potential for unintended consequences the CWG suggests penalties should be phased in over several years to ensure the framework operates as expected.
3. Payment Adjustment Mecham: Can you support a monthly cap at 300%? Does the approach achieve the intent of reasonably limiting adjustment payments?	The CWG proposal largely solves the settlement issue solved by a monthly settlement cap. However, the CWG would propose the monthly cap should not be a penalty cap, but rather a settlement cap to protect generators from cash flow issues. Accordingly, the CWG would support a smoothing of penalties over time. Based on the current design, failure to perform during an EEA event could cause a generator to be penalized an amount greater than its annual capacity payment. While the CWG supports the 1.3x annual cap, it would note that from a settlement perspective it is preferable to pay that amount back more slowly over time. The CWG would suggest a monthly cap of 100-150% of monthly capacity market revenue. In this way, if a generator owes the AESO 50% of its annual revenue following poor performance during an EEA event, the AESO could collect that money by withholding capacity payments for six months (monthly cap of 100%) or by charging a more manageable amount to the capacity provider in addition to withholding capacity payments (monthly cap as high as 150%).
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?	The CWG supports this approach. It strikes a good 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. The CWG considers that the AESO has achieved this goal with its proposed penalty cap. The CWG cautions the AESO to ensure that in order to maintain the balance, the penalty assessment scheme should not effectively cap penalties at a lower value. Specifically, penalties should not effectively be capped at significantly less than 100%. Lastly, the CWG would suggest that there is some benefit to phasing in the penalties slowly as the capacity resources become accustomed to the new market. As such, it may be appropriate to cap the penalties closer to 100% in the first several years to ensure the system operates as expected.

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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?	The CWG supports this approach given that it only mitigates market participants that have a large enough portfolio that the capacity provider has the ability to exercise market power. The CWG strongly supports this principled approach to market power mitigation. This minimizes the administrative burden creating efficiencies while still 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 the CWG supports the use of a price cap as an ex-ante mitigation measure, applied only to participants who have market power, the CWG considers 0.5 x net-CONE to be too low. Mitigation shouldn't push offers below competitive levels and net-CONE is the long-run 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. Further, in that net CONE is an unpredictable number and may not tie to existing generators, the CWG sees value in adding a second screen, such that the no-look limit would be the greater of 1 x Net Cone or $x/kW. In other markets the offer cap for mitigated resources is often below 1 x 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. Further, the CWG would suggest that retiring units have an additional option. In the case where a generator announces prior to the auction their intent to retire an asset, that asset should be able to offer any amount up to the price cap, even if the generator is usually subject to market power mitigation, under the condition that the asset will be retired in the delivery year if it doesn't clear.
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?	Yes. The CWG supports the AESO's decision that there will be "no minimum offer price requirements for capacity resource suppliers due to net-short capacity positions or out-of-market payments." For further information please see past CWG submissions that outline the CWG position on MOPRs.
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?	CWG supports flexibility for market participants. To the extent this is used to exercise market power, this should be monitored. In other cases, it should be allowed. The CWG suggests that assets should have the ability to apply for a UCAP adjustment as necessary, as noted in response to question 1. The assets should be able to apply for a UCAP de-rate wherein the asset can sell less or no capacity into the market after completing the AESO application. This will provide the AESO with visibility to understand why the asset expects to be unable

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	to delivery on a capacity commitment, allowing the AESO to adjust its modeling as required.
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? b. For long outage requirements that are for a substantial portion of the year?	CWG supports flexibility for market participants. As noted, greater scrutiny of mothballing may be appropriate due to concerns for unclear market signals. De-listing should simply require sufficient notice that the market can adjust. Transparency as to the nature of the de-listing is also required for participants to have informed views on market conditions.
10. Transition to Capacity Market: Is a rebalancing auction for first obligation period 2021/22 required and practical?	The first auction will take place over a year in advance of the first delivery year. The AESO and market participants have generally agreed that a rebalancing auction should occur 3-months in advance of each delivery year. The first delivery year should not be an exception. The first auction is likely at a higher risk of inaccuracies than other auctions as participants need to learn the rules of a new system. It is important to provide market participants the option to sell out of their capacity obligations if they consider themselves overcommitted when reaching the 3-month mark. If the AESO is not amenable to holding a 3-month rebalancing auction for the first delivery year, the CWG would propose that there are simply no penalties in the first delivery year. In this case the penalties should still be calculated and assets informed of the penalties they incurred, however, no assets will be required to pay penalties (at least not beyond a 100% claw back of capacity market revenues from that delivery year). This will allow for a learning year where generators begin to learn how the capacity market will impact them financially and allows the AESO to skip the rebalancing auction without causing financial hardship to any assets.

General Comments

Retirements

The CWG does not support the AESO's current proposal that retirement now 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." 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 will be numerous projects that could be developed in response to retirements.

The CWG suggests that the primary concern being addressed by this rule is that resources could announce retirement before an auction creating a need for new capacity of which other market participants were not given notice. The CWG suggests that this can be solved by requiring retirement announcements at least 3 months prior to the capacity market auction for the delivery year. There should not be a test to approve the retirement, only rules around retirement announcements.

On the other hand, the CWG would support more stringent rules on mothballing as mothballing does raise prices while continuing to discourage new entry. This is the case as new entrants are aware that the mothballed unit will be returning to the market. Retirements do not cause the same issue because a new entrant will be incented to enter the market as soon as it is economic to replace the retired unit, preventing the same issues that can occur through mothballing.

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. The CWG strongly supports this approach. Without a threshold, it would be possible for the UCAP to adjust downward at the 18-month rebalancing auction, requiring the generator to buy out of its obligation for a number of MWs, then for the UCAP to correct upwards for the 3-month rebalancing auction, allowing the generator to re-sell that additional obligation. This creates a problem. Accordingly, the CWG suggests one of three solutions be implemented: (1) the threshold-based approach with an adequately wide threshold; (2) selling out of obligations be optional at the 18-month auction and only required at the 3-month auction; or (3) that the UCAPs not be adjusted by the AESO at the rebalancing auction, allowing participants to sell out of their obligations if they consider it necessary, which leaves the penalty mechanism as the incentive for participants to ensure they are committed to an accurate UCAP.