Stakeholder Comment Matrix – March 14, 2019

Tariff Design for Capacity Market and Bulk and Regional Transmission Cost Allocation – Industry Update (March 13, 2019)

Period of Comment:	March 14, 2019	through	April 10, 2019	**Contact:**	Colette Chekerda, P.Eng. ADC Executive Director
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Date:	[2018/04/8]			**Email:**	colette@carmal.ca

Please provide comments relating to the topics listed below in the corresponding box. For convenience, references to slides from the March 13 Industry Update where each topic was discussed are included in the table below. Please include any views about whether the content presented sufficiently addressed the topic, and provide any proposed alternative or additional approaches that should be considered.

Slides	Topic	Stakeholder comments
Tariff Design Consultation Process		
5-11	AESO tariff design consultation approach, scope, and process.	ADC agrees with AESO approach on working together with industry on developing recommendations for cost allocation of costs for the capacity market and for the Bulk and Region components of the DTS tariff. While the TDAG has representation from a variety of stakeholder groups, it is important to weigh the input on the recommendations more heavily from those that are paying the costs (industrial, commercial, residential) than those that aren't exposed to them (TFO's, DFO's, and generators with the exception of losses).
Capacity Market Cost Allocation Tariff Development Update		
15-20	Requirements of *Capacity Market Regulation*	The ADC view is that the Government, in setting out the regulation as it has, believed that a weighted energy method would not only allocate costs to time periods where the system is expected to most need capacity, but would also provide a price signal to modify consumer behavior over the long term with the desired result of reducing the overall capacity procurement volume. In order to achieve a consumer response, the peak pricing needs to be sufficiently high to economically justify the response, and of sufficiently short duration so that it doesn't lead to uneconomic productivity loss. The government had this in mind when it set out that up to 4800 hours could have zero weight, and that a peak block required a minimum of 200 hours. History provides a useful guide in peak pricing weights and duration. The energy only market has historically been volatile. It is in the high priced hours that generators recovered a contribution to their capital investment. The market volatility, and high priced hours, resulted in energy intensive and trade exposed industrials investing significant capital into their operations to quickly adjust production to the real time electricity price.

<table>
<tr><th>Slides</th><th>Topic</th><th>Stakeholder comments</th></tr>
<tr><td></td><td></td><td>
Our observation is that the pool price needed to be at least $250/MWh to generate a load response. The following table shows the reduction in commodity costs by responding to this threshold.
<table>
<tr><th>Year</th><th>Average Pool Price</th><th># of Hours Pool Price >$250/MWh</th><th>% of Hours Pool Price > $250/MWh</th><th>Average Price by avoiding Pool Prices > $250/MWh</th><th>% of Pool Price Reduction</th><th>Average price in on peak hours excluding prices >$250/MWh</th><th>Average Price during Pool Price > $250/MWh</th><th>Price Ratio of Super Peak to Mid-Peak Hours</th></tr>
<tr><td>2005</td><td>$70.36</td><td>294</td><td>3%</td><td>$58.69</td><td>17%</td><td>$73.21</td><td>$406.38</td><td>6</td></tr>
<tr><td>2006</td><td>$80.79</td><td>498</td><td>6%</td><td>$56.17</td><td>30%</td><td>$70.38</td><td>$489.18</td><td>7</td></tr>
<tr><td>2007</td><td>$66.95</td><td>279</td><td>3%</td><td>$51.56</td><td>23%</td><td>$66.04</td><td>$534.90</td><td>8</td></tr>
<tr><td>2008</td><td>$89.95</td><td>513</td><td>6%</td><td>$62.38</td><td>31%</td><td>$76.61</td><td>$534.52</td><td>7</td></tr>
<tr><td>2009</td><td>$47.81</td><td>158</td><td>2%</td><td>$38.34</td><td>20%</td><td>$47.47</td><td>$563.41</td><td>12</td></tr>
<tr><td>2010</td><td>$50.88</td><td>219</td><td>3%</td><td>$38.56</td><td>24%</td><td>$48.10</td><td>$531.56</td><td>11</td></tr>
<tr><td>2011</td><td>$76.22</td><td>581</td><td>7%</td><td>$36.58</td><td>52%</td><td>$46.67</td><td>$634.27</td><td>14</td></tr>
<tr><td>2012</td><td>$64.32</td><td>512</td><td>6%</td><td>$31.17</td><td>52%</td><td>$39.50</td><td>$599.88</td><td>15</td></tr>
<tr><td>2013</td><td>$80.19</td><td>612</td><td>7%</td><td>$38.46</td><td>52%</td><td>$47.98</td><td>$635.65</td><td>13</td></tr>
<tr><td>2014</td><td>$49.42</td><td>196</td><td>2%</td><td>$34.89</td><td>29%</td><td>$41.39</td><td>$683.94</td><td>17</td></tr>
<tr><td>2015</td><td>$33.34</td><td>138</td><td>2%</td><td>$23.20</td><td>30%</td><td>$26.51</td><td>$666.66</td><td>25</td></tr>
<tr><td>2016</td><td>$18.28</td><td>4</td><td>0%</td><td>$18.06</td><td>1%</td><td>$19.82</td><td>$500.78</td><td>25</td></tr>
<tr><td>2017</td><td>$22.19</td><td>14</td><td>0%</td><td>$21.29</td><td>4%</td><td>$23.67</td><td>$583.21</td><td>25</td></tr>
<tr><td>2018</td><td>$50.35</td><td>171</td><td>2%</td><td>$39.43</td><td>22%</td><td>$45.15</td><td>$611.30</td><td>14</td></tr>
</table>
Historically, by responding to energy prices greater than $250/MWh, energy intensive and trade exposed loads have been able to manage their electricity costs to between $20/MWh to $40/MWh in a wide range of annual pool price outcomes by responding to ~ 200 to 500 hours per year.
This history should be relied upon to inform the tariff design.
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<tr><td>21-22</td><td>Resource adequacy model and unserved energy</td><td>The resource adequacy model wasn’t intended to predict with accuracy tight supply cushion hours. The cost allocation weights and time-blocks should take more than one obligation period into consideration to lessen any year to year anomalies – such as the OCT 2021-2022 EUE distribution. As the RAM model evolves, it may be useful to put in known planned generator outages into the model to get a more</td></tr>
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Slides	Topic	Stakeholder comments
		accurate picture of the EUE distribution.
22	Distribution of expected unserved energy throughout the obligation period	There seems to be some anomalies with the distribution, the output should be revisited with any modifications that result from the Capacity Market proceeding 23757.
23-27	Bookend scenario analysis	ADC supports the bookend analysis that was completed.
25	Observations on bookend analysis results	The bookend scenarios are indicative of the changes to the procurement volume. The wide peak results in an increase in volume and the narrow peak results in a decrease. The spread between the 2 bookends is 71 MW. While it is difficult to precisely determine how much impact that would have on the overall capacity market, over time, the narrow book end has a greater likelihood to reduce capacity costs for the market and should be recognized in the design.
26	Objectives for cost allocation rate design	The cost allocation should incent a load response in a sufficiently small number of hours that has the highest likelihood of EUE.
28-30	Development of 400-hr on-peak time block	The ADC can support a 400 hour peak time block, but fewer hours would be better. The 3 hour response for July to Oct is more difficult for loads to interrupt than a 2 hour block. Especially since it is 5 days a week.
31-32	Considerations for weights of time blocks	The peak time block should have a sufficiently high price to get a load response. Historically the price that loads started to respond at was ~$250/MWh and the average cost that was avoided during these hours was in the order of $500 to $700/MWh. See table above. If the price is high enough, it will spur investment in demand response, storage, and also in product offerings to commercial and residential customers who need to see a real economic benefit to change behavior.
33-34	Potential rate ranges	The ADC would support a range in the 12:1:0 to 20:1:0 weightings illustrated on slide 34. If the capacity market revenue reaches $1.5B, then as a collective we need to revisit the capacity market design and whether it is delivering on its key objective of reliability at a reasonable cost.
34	Appropriate range of weight ratios to consider	The higher ratios will encourage a load response, where the lower ratios will not spur investment into flexibility.
35-38	Additional considerations for rates	ADC agrees there are numerous considerations to factor into the decision, however the alternate cost recovery chart on slide 38 will not incent any demand response and should be discarded.
39-43	Terms and conditions considerations	The ADC supports the AESO's determination that capacity costs and transmission costs don't need to be settled at the same measurement point.
40	Regulation does not permit penalties or incentives	The ADC supports the AESO's conclusion on penalties and incentives
42	"Gross up" of POD metered volumes to adjust for distributed generation	ADC supports that POD metered volumes need to account for distributed generation so that all load that isn't a self supplier pays capacity costs. This will also avoid the potential concern of a distributed generator getting paid twice for capacity. Note that if capacity costs would

Slides	Topic	Stakeholder comments
		have been added to settled energy through the retailer, this wouldn't have been an issue.
43	Preferred approach for deferral account true-up	ADC supports the AESO approach. Agree that if deferral accounts are small (the AESO may want to set a threshold) then a prospective rider is appropriate. If the deferral account is not small, then ADC suggests a year end reconciliation to assign costs (or benefits) to the time blocks they were charged in.
44	Allocation of capacity market costs to transmission losses	No Comment
45	Capacity market cost allocation remaining work	ADC supports that further work is required and that examination of consumer bills is important. It is also important to not put industry at risk because of the rate or market design. ADC's expectation is that the capacity market revenues are intended to recover the "missing money" for generators and the overall capacity market revenue requirement should be much lower than the energy market. If this turns out not to be the case, and the capacity revenue becomes the main source of revenue for generators, then the entire rate design and regulation will need to be reexamined to determine if it is delivering on its objective of reliability at a reasonable cost.
Update on Bulk and Regional Transmission Cost Allocation		
48-51	Bulk and regional transmission cost allocation current work, future work, and next steps	ADC will continue to participate in these efforts.
Additional Comments		
—	Please add any additional comments related to tariff design for allocating capacity market and bulk and regional transmission costs should be considered.	The ADC submits that the delivered electricity cost outlook for Alberta is growing larger, becoming more complex, and providing fewer opportunities to manage costs. Competitiveness of Alberta industry needs to remain a key objective of this work.