CMD Final Industry Stakeholder Comment Matrix

The AESO invites stakeholders to provide comments on the final Comprehensive Market Design (CMD Final). All feedback (whether it be general or specific in nature) will assist in the development of the suite of ISO rules for the implementation of the capacity market. With respect to comments provided in relation to the “Specific Feedback Questions”, please note that your responses will also help to inform future consultation activities, including the topics to be discussed during upcoming stakeholder sessions expected to be planned for the end of July/early August.

Please review the instructions below and submit your feedback to capacitymarket@aeso.ca no later than 3:00 p.m. on Friday, July 20, 2018.

The AESO will post all feedback “as received” on www.aeso.ca by Wednesday, July 25, 2018. Please note that the names of the parties submitting each completed comment matrix will be included in this posting. Please also note that the AESO will not be responding to individual submissions.

Instructions

- Stakeholders are requested to provide all feedback on CMD Final within this matrix.
  - if it is believed necessary to submit additional supporting documentation, please clearly indicate which section of CMD Final or topic your document refers to. No handwritten comments will be accepted.

- Please input your name and the organization you are representing in the comment boxes provided below each CMD Final section. Your contact information is requested in each section for ease of sorting and compiling feedback from all stakeholders.
  - Press Shift + Return to enter paragraph breaks within a comment box.
  - Comment boxes will automatically expand if additional room for feedback is required.

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

CMD Final Glossary

1) *Which, if any, of the defined terms in the glossary do you find vague, confusing, or unnecessary? Please identify each defined term and explain how it may be improved.*

   (insert response here)

2) *What gaps or disconnects may exist as between the glossary and the sections of CMD Final? Please identify any relevant terms, definitions, and/or specific content in CMD Final.*

   (insert response here)

3) *Which, if any, of the definitions in the glossary contradict the AESO's current Consolidated Authoritative Document Glossary? Please identify each term and corresponding definition, and describe the concern.*

   (insert response here)

4) *Which terms, if any, do you believe are missing from the glossary? Please provide each term that is missing and suggest an appropriate definition.*

   (insert response here)

5) *Do you have any other feedback specific to the glossary that you would like to provide?*

   (insert response here)

Name: Click or tap here to enter text. **Organization:** Click or tap here to enter text.

CMD Final Section 2: Supply Participation

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   Self-supply Designation
   TCE does not support the proposal that a self-supply status designation must remain in effect for at least 4 years. This 4-year designation commitment, combined with the 3-year forward period and a 1-year obligation period, effectively creates an 8-year status commitment that significantly restricts the flexibility of Alberta businesses. TCE acknowledges that sites should declare their intention to self-supply in advance of an auction and that they must meet their capacity market obligations during the delivery period. TCE submits that this provides adequate market certainty. Although it is expected to be rare for self-suppliers to exercise the option to switch status, self-suppliers should maintain the flexibility to switch if needed in response to changes in their business, changes in law, or changes in market rules. These events will not neatly align on a four-year cycle, nor are they necessarily tied to a physical change to the operation of the site. Given that changes to self-supply status will impact only the volume of UCAP procured and not the demand curve shape, there is no need to restrict status changes to every four years to align with demand curve approvals. Restrictions should not be unnecessarily imposed that restrict the flexibility of Alberta businesses.

   If the AESO decides not to remove the proposed self-supply status designation limitations, TCE submits that the available exclusions to this limitation need to be expanded beyond physical changes to the operation of the site. As stated above, self-suppliers must be able to respond to changes in their business, changes in law, and changes to market rules. It is important to recognize that not all self-supply sites are structured the same way. In some cases, the generator and the host are separate entities in which the self-supply site is structured via contractual arrangements that pre-date the capacity market and change over time. As such, there is a legitimate need for the ability to change a self-supply designation due to business or contractual changes.

   Permanent Delists
   TCE submits that if the AESO prevents an asset from retiring for reliability purposes, the AESO should be required to provide adequate compensation.

   Temporary Economic Delists
   TCE suggests that the AESO should only be concerned about temporary economic delisting in cases where the market participant has market power. TCE recommends that temporary delists be automatically approved if the asset owner passes the capacity market power screen.

SPECIFIC FEEDBACK QUESTIONS

The AESO is also specifically requesting feedback on the following question(s):

1) *Is the description of the required thresholds to be classified as a refurbished asset clear? What additional considerations or further detail may be required, regarding the determination of these thresholds?*

2) *Is the description of the mechanics of making refurbishment offers and the associated market clearing mechanism clear? If not, please explain.*

3) *What additional considerations or further detail may be required regarding the conditions under which temporarily delisted assets can return to service during an obligation period?*

   Temporary economic delists should be able to end at the owner's discretion when changing market conditions make a return desirable. Consider the possibility that something critical happens to a large asset and it is not expected to be able to return to service for many months. In this case, pool prices will be high and reliability may be at risk. The delisted asset should be able to return to service to lower costs to consumers and increase reliability. Accordingly, the rules need to be adequately flexible to allow a return subject to sufficient notice.

   Further, TCE submits that the AESO's provisions should be symmetric since supply shocks can impact supply in both direction. TCE agrees that an asset should be able to cancel its temporary economic delist if market conditions improve and similarly submits that an asset with no capacity commitment should be able to delist temporarily during the delivery year if energy market conditions deteriorate. In this circumstance, there should be no reliability concerns because: (i) the asset has no capacity commitment; and (ii) the deteriorating market conditions are indicative of over-supply. This would allow these assets to optimize their availability for energy market price signals.

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Mark Thompson Organization: TransCanada Energy Ltd. (TCE)

GENERAL FEEDBACK QUESTIONS

- *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

(insert response here)

- *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

(insert response here)

- *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

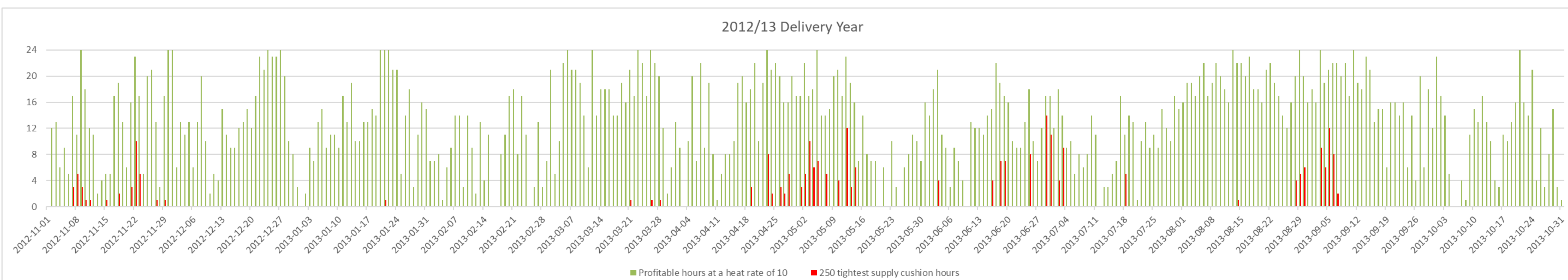
(insert response here)

- *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

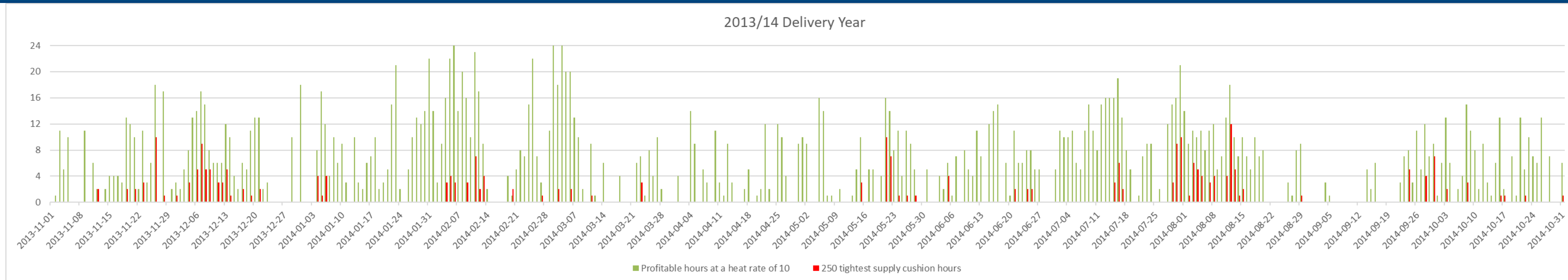
<u>More Hours Are Required in the UCAP Calculation and Performance Framework</u>

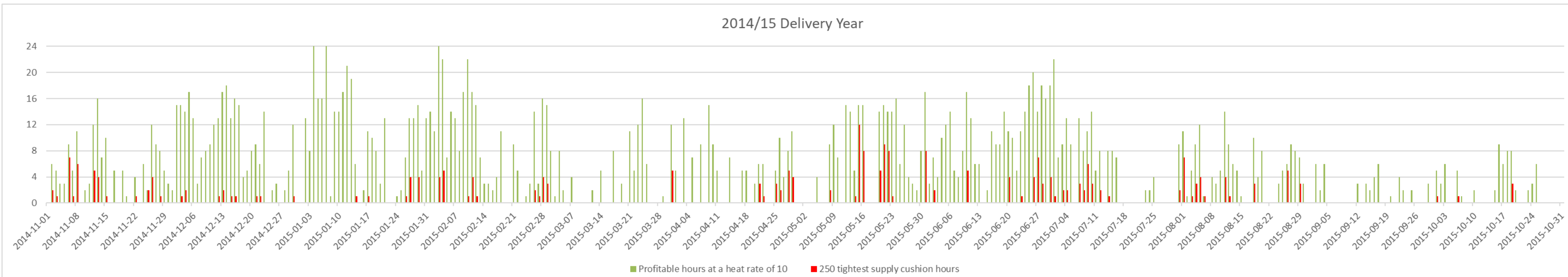
TCE recommends the AESO use 1,000 hours per year for the calculation of UCAP. While the use of 250 hours per year is better than 100 hours, TCE has the following concerns:

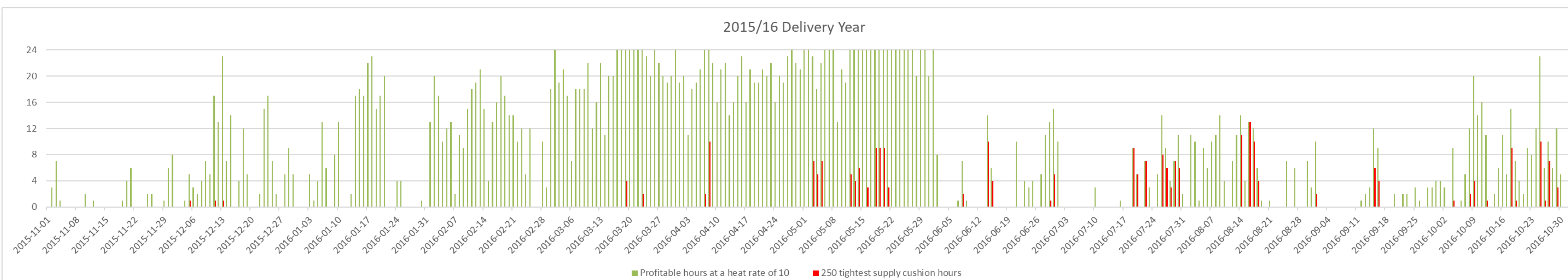
- The use of 250 hours per year represents only 2.9% of the annual hours, and will account for all capacity market revenues and a large proportion of energy market revenues. Historically, under the energy-only framework, approximately 1,140 hours per year returned 90% of the annual profits for a peaking plant (evaluated at a 10 heat rate). Accordingly, the current proposal imposes a significant increase in risk compared to the energy-only framework, contrary to a key goal of the market transition. In its original recommendation paper, the AESO stated that the capacity market was required to increase revenue certainty and reduce risks for investors because the energy revenues were expected to be more volatile and more concentrated due to a significant increase in intermittent renewable generation. The currently proposed UCAP and penalty framework do not accomplish this goal. Increasing the number of hours in the UCAP calculation to 1,000 is more consistent with historical levels of risk from a delivery perspective. More hours will average out risks of random scarcity events over the year. Using 1,000 hours will create a UCAP system that will be more representative of the capacity product and more stable from year to year, which will reduce risk to generation investments. In the following charts each green bar indicates the number of profitable hours for the day over the course of one year. Each red bar indicates the number of hours for the day that were among the 250 tightest supply cushion hours for the year and thus represents the hours that provide value under the proposed framework. As shown in the charts, the number of hours that provide value under the proposed framework is significantly reduced relative to the energy-only framework.

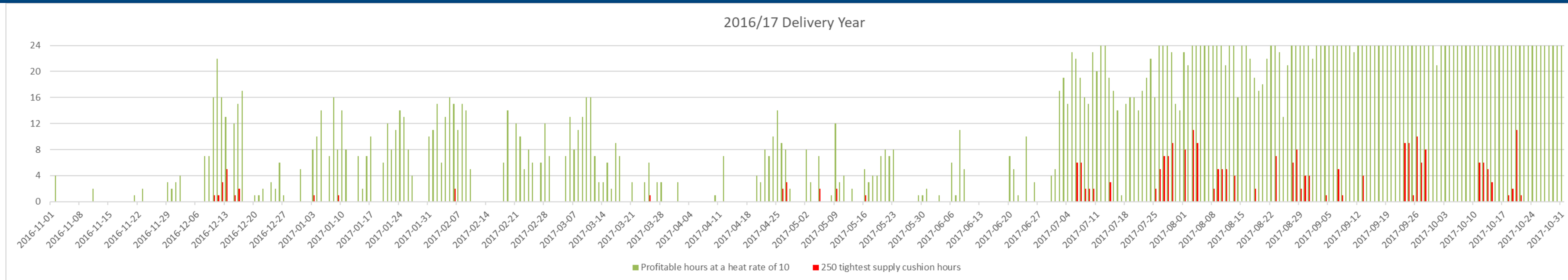


CMD Final Section 3: Calculation of UCAP

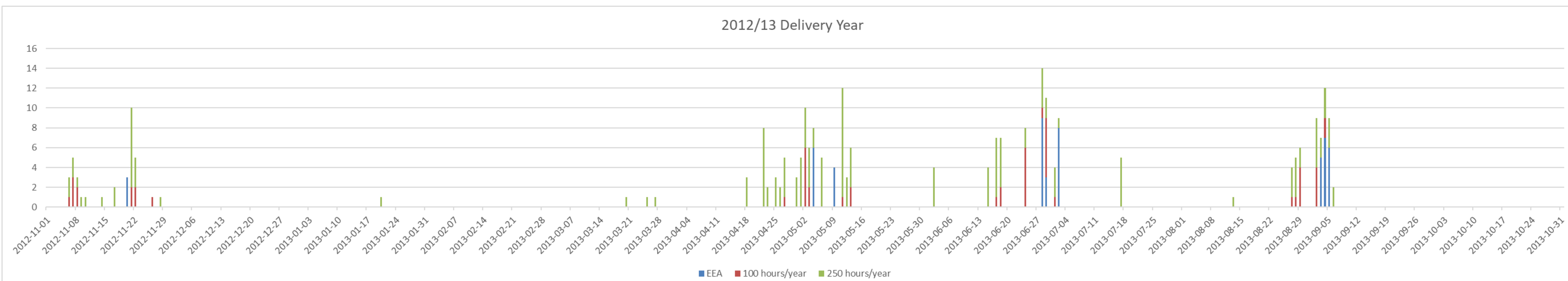


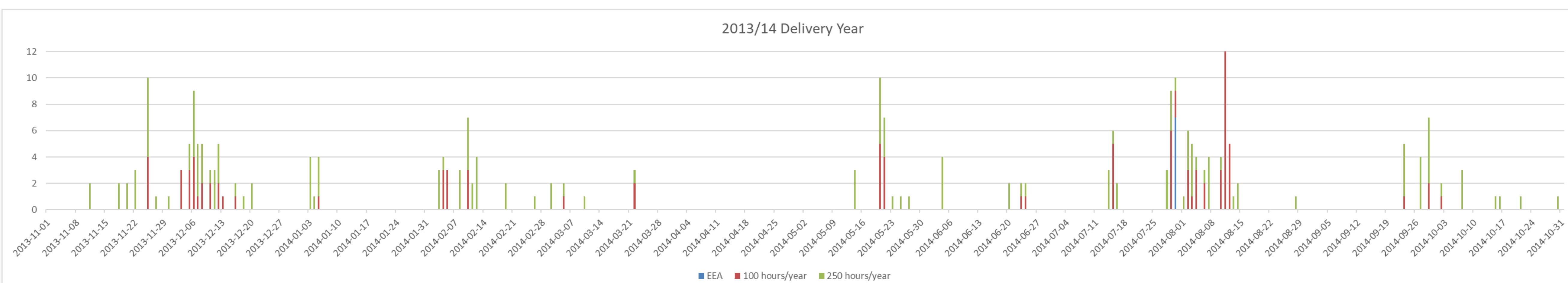


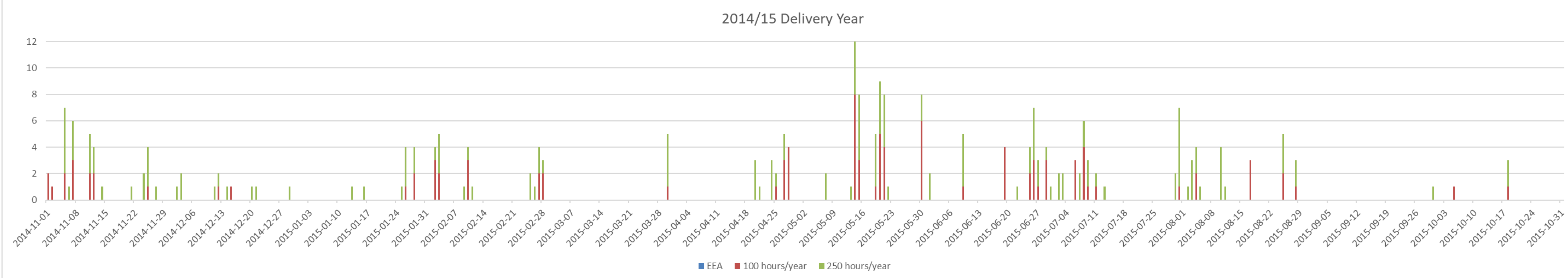


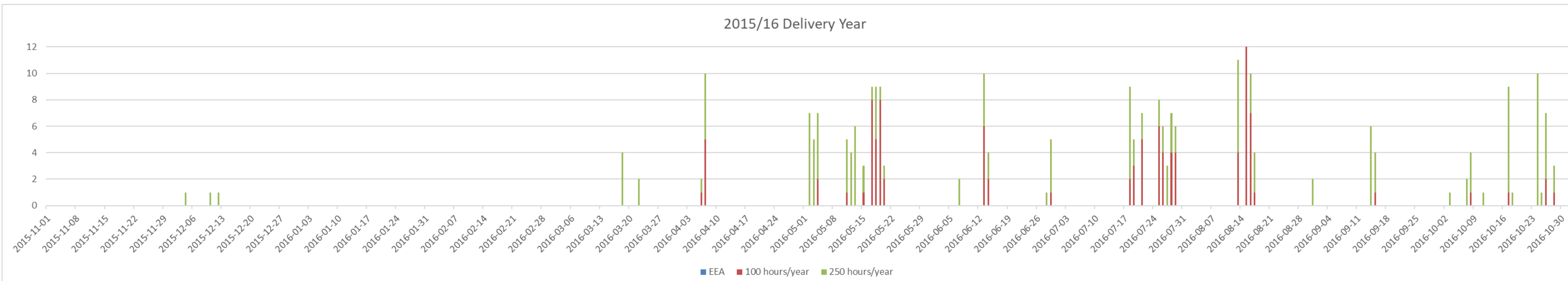


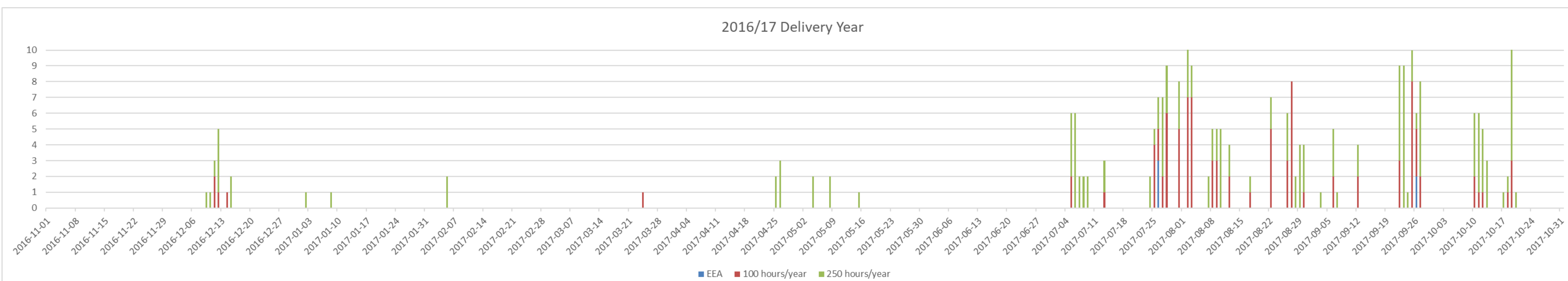
- The use of 250 hours per year does not materially diversify delivery risk, relative to the use of 100 hours per year, as the hours cluster and are typically contained within a small number of events. Increasing number of hours per year in the UCAP calculation to 1,000 increases the number of days and number of weeks measured. Using historical data over a five-year period, the tightest 1,000 hours per year would include at least one data point in almost 30 individual weeks and over 150 different days. This allows for a true diversification of risk in a way that 250 hours does not allow. The graphs below show the days covered by the 100 tightest hours in red and the incremental hours that would be added by moving to 250 hours in green. Where green hours are added on the same days that already contained red or blue, the additional hours have not diversified generator risk, especially outage risk.











- While the UCAP for classes of assets may be relatively stable, individual generator UCAP varies materially from year to year creating revenue uncertainty. Increasing the number of hours reduces risk and should increase the stability of UCAP at the individual asset level year over year. Further, AESO analysis shows stability of aggregate UCAP values by asset class between 100 and 600 hours; increasing the number of hours should therefore not materially increase the UCAP estimate for the system or asset classes but will ensure UCAP values are not artificially too low (which may result in over procurement by the AESO).

CMD Final Section 3: Calculation of UCAP

Transmission Constraints

The AESO proposes to exclude transmission constraints from UCAP determinations except in circumstances where a transmission outage causes a generator to disconnect from the system. TCE agrees that transmission constraints should be excluded from UCAP determinations, and that this should also include transmission outages that cause a generator to disconnect from the system. In general, it is not in the spirit of just and reasonable rates or the FEOC principles to penalize a market participant for a transmission outage it did not cause. In this case, the impacts to a market participant would be patently unfair if the event was severe enough to cause disconnect. Not only would the market participant suffer lost revenue, as is the case currently, but the proposed treatment would reduce UCAP and potentially trigger capacity market penalties.

SPECIFIC FEEDBACK QUESTIONS

- *Is the regression-based approach to determining UCAP for gross dispatched self-suppliers clear? What additional considerations or further detail may be required, to sufficiently describe this approach?*

  The regression analysis to approximate an availability factor for self-supply assets is an improvement over the previous approach, but creates the potential of a disconnect between actual performance and deemed performance in a given hour. In effect, in many hours the regression will give a materially different result than the actual performance. This creates a 'sampling' risk that the availability assessment will be based on deemed performance that is not reflective of actual performance.

  The UCAP determination should be simplified and simply use an availability approach for all dispatchable assets. Based on a review of several sites, the regression approach does not give materially different results than simply adding undispatched MWs to net to grid volumes per the simple availability approach. A simple approach should be preferred particularly as the results appear to be largely similar.

- *What additional considerations or further detail may be required regarding the process for determining external resource UCAPs?*
- *What additional considerations or further detail may be required regarding the UCAP refinement process?*
- *Should the list of events under which a refinement request can be submitted as provided in section 3.2.2.a.i be further defined? If so, please provide your suggestions.*

  TCE recommends the AESO make a small change to 3.2.2.b to permit both physical and contractual changes that will impact the UCAP of the site. This change is required to account for possible contractual changes at self-supply sites where the generator and host are separate entities and where contractual changes could increase or decrease the UCAP.

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Mark Thompson Organization: TransCanada Energy Ltd. (TCE)

CMD Final Section 4: Calculation of demand curve parameters

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

The desired end state calls for reliability at low cost to consumers. The current demand curve parameters will not achieve this goal, or the goal of reasonable cost, as the significant oversupply will increase consumer costs. Further, the oversupply will shift incremental value to the capacity market, which is not a hedgeable product.

TCE would further note that Bill 13 calls for reasonable cost to consumers, not lowest costs, and, accordingly, the AESO should adjust its desired end state.

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

(insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

(insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

Use of the Forward Market

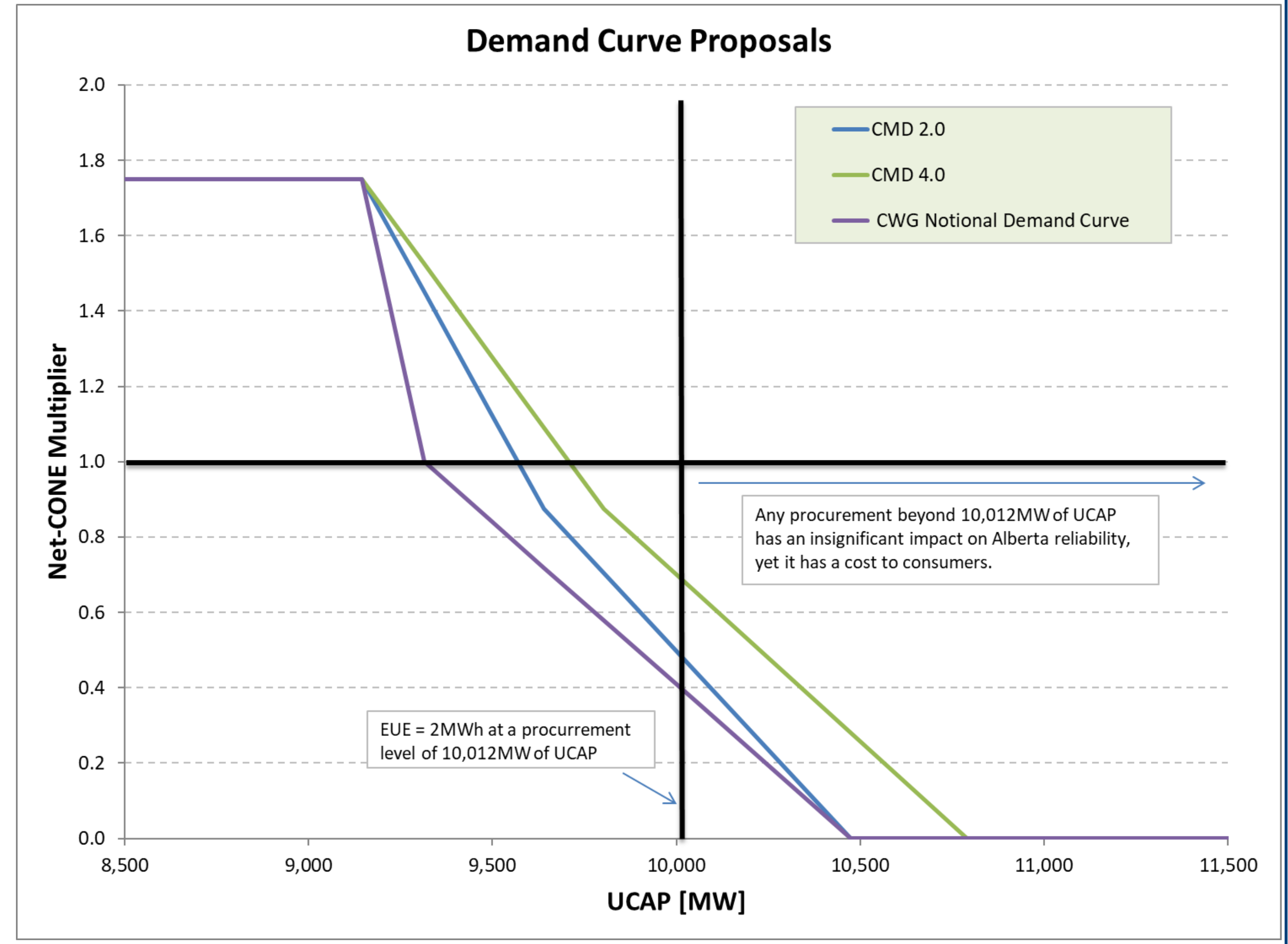
The use of the forward curve to set the energy market revenue for the entrant creates a number of issues that must be considered. The Alberta market is not liquid 3 years in the future, and small volumes can materially move price. This gives rise to the concern that the prices are not representative, as well as the concern that participants will be 'at risk' for forward transactions. For example, if a large participant enters into a forward transaction that moves the market in any material way, that participant will notionally be at risk for allegations that the transaction impacted its capacity market portfolio. This adds compliance risk for every transaction for a market that is already illiquid. The feedback loop between energy prices and the capacity market must be carefully considered and using the forward market to set net-CONE should not be the approach due to Alberta's small, illiquid market. Further, translation from forward prices to revenue for the reference technology is also not straightforward as plant utilization still needs to be forecasted.

Last, the energy revenue for the net-CONE calculation should be made assuming the market is in equilibrium. Otherwise, over-supply would drive future capacity prices up while under-supply would drive capacity prices down, which sends the wrong incentives. This can be achieved through a model, where forward prices would reflect market expectations for the delivery period, which may or may not reflect over- or under-supply.

CMD Final Section 4: Calculation of demand curve parameters

Demand Curve Parameters

TCE has concerns with the current demand curve proposal.



- The design continues to bias the Alberta market to a significant over-supply of capacity, with the associated impact of depressed energy prices. This has two main impacts: (1) the capacity market will become the primary driver of investment decisions; and (2) Alberta customers will face materially higher costs than necessary.
- AESO analysis showed that an EUE of 2MWh is achieved at a procurement volume of 10,012 MW of UCAP. TCE submits that there is no significant reliability gain in procuring beyond 10,012 MW of UCAP and accordingly pricing capacity at approximately 0.7 net CONE at that point is extremely inefficient and costly to consumers.
- The rightward shift from CMD 2.0 to the CMD 4.0 curve is a shift in the wrong direction that increases consumer cost for minimal increase in reliability.
- There are more effective and market ‘friendly’ ways to ensure adequacy in the face of uncertainty instead of simply purchasing excess capacity. TCE is concerned that the AESO has not yet provided analysis or rationale supporting the move to over procurement as opposed to other measures to address the apparent concern that the capacity market will not be able to consistently deliver enough capacity without a ‘cushion’ of about 500 MW over the true target. The approach utilized is an extremely expensive form of insurance against a problem that may not even exist in Alberta.
- The CMD 4.0 continues to show the demand curve intersection with the target procurement level priced above net-CONE. This results in an unacceptable bias towards over procurement. It is synonymous that the demand curve intersects the assumed target at net-CONE. Only in that circumstance will the market converge to the desired level of reliability. A demand curve that intersects the target procurement above net-CONE will inherently converge to persistent over-supply, just like every demand curve that intersects the target below net-CONE would converge to persistent under-supply. A demand curve with this property (purple) is illustrated in the graphic and represents a far more efficient and cost-effective solution for the market.
- The capacity market is unlikely to provide the same incentive for efficient, flexible generation as a healthy energy market and accordingly, TCE is concerned that the bias to oversupply, in addition to being costly, will not result in the type of responsive generation expected to be required to support integration of intermittent renewables.
- TCE supports the current proposal to clear on the demand curve. Given the expectation that many existing resources will price most or all of their offer blocks at or around $0, as they will be price takers, it is important to price on the demand curve and allow capacity prices to be paid to generators.
- TCE considers that it is important for all parameters to be well reasoned and justified. At the moment, it is difficult to support individual parameters of the demand curve as the AESO has not explained its logic in selecting those parameters. TCE requests that the AESO explain, in detail, its rationale for selecting each individual demand curve parameter.

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Lars Linder Organization: TransCanada Energy Ltd (TCE)

CMD Final Section 5: Base auction

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   (insert response here)

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Click or tap here to enter text. **Organization:** Click or tap here to enter text.

CMD Final Section 6: Rebalancing auction

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   (insert response here)

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Click or tap here to enter text. **Organization:** Click or tap here to enter text.

CMD Final Section 7: Capacity market monitoring and mitigation

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   (insert response here)

SPECIFIC FEEDBACK QUESTIONS

1) *What additional considerations or further detail may be required regarding how the AESO will conduct the ex ante market power screen to identify firms that will be subject to capacity market mitigation?*

   TCE continues to support an asset-specific offer price cap of no less than 0.8 x net-CONE, with a preference of a cap set at 1 x net-CONE.

2) *What additional considerations or further detail may be required regarding the determination of asset specific offer caps?*

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

   (insert response here)

Name: Mark Thompson Organization: TransCanada Energy Ltd. (TCE)

CMD Final Section 8: Supply obligations and performance assessments

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   Performance Framework

   TCE continues to submit that the overall performance penalty/incentive scheme remains too complex and is not achieving the desired outcome. The penalty and incentive mechanism should ensure that what is purchased is delivered.

   Significant and punitive penalties beyond revenue claw-back are not required as a failure to perform during the 250 tightest hours will result in a lower UCAP, which is a significant penalty in and of itself. In other markets, penalties are intended encourage availability in specific hours. However, in those markets, the UCAP is based on performance throughout the year. In Alberta, the UCAP is calculated based on performance in the specific hours when the system is at risk for reliability. Given that non-performance in the 250 tightest hours will result in lower capacity revenues in future years (the impact of the reduced UCAP will be for the next five years), the penalties in Alberta should not be of the same magnitude as the penalties being introduced in other markets.

   The largest concern with the proposed mechanism is the risk that a single event can claw-back a material portion of a generator's revenue merely by circumstance. A 7-hour EEA event occurring on a single day could erode more than 25% of a unit's capacity value for the year. Penalties of this scale are simply not required, nor can they negate the reality that outages occur. TCE believes that the AESO proposal would be ineffective at incenting performance in general while simultaneously increasing uncontrollable risk during a small and unpredictable number of hours.

   Asset Substitution and Volume Reallocation Framework
   The asset substitution and volume reallocation framework does not appear to result in a full substitution or reallocation. An asset that has substituted/reallocated out of its obligation should be treated the same as if it had never taken on the obligation in the first place, which is consistent with the principle that UCAP is a fungible product. Pursuant to section 8.3 of CMD Final, this is not the case as the substitution/reallocation would not apply to availability assessments. TCE recommends that the asset substitution and volume reallocation framework apply consistent treatment to each MW of UCAP.

SPECIFIC FEEDBACK QUESTIONS

1) *What additional considerations or further detail may be required regarding how the AESO will assess whether demand response assets have obtained a sufficient load volume prior to the second rebalancing auction?*
2) *What additional considerations or further detail may be required regarding how the performance of external capacity assets will be measured during availability and delivery assessment periods?*
3) *Should the list of events under which availability and delivery assessments will not be conducted as provided in section 8.2.39 be further defined? If so, please provide your suggestions.*

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

CMD Final Section 8: Supply obligations and performance assessments
(insert response here)

Name: Mark Thompson Organization: TransCanada Energy Ltd. (TCE)

CMD Final Section 9: Settlement and credit requirements

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   (insert response here)

ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

Name: Click or tap here to enter text. **Organization:** Click or tap here to enter text.

CMD Final Section 10: Roadmap for changes in the Energy and Ancillary Services Markets

GENERAL FEEDBACK QUESTIONS

1) *Please provide your feedback as to whether the design in this section meets the desired end state and criteria set out for Alberta's capacity market design?*

   (insert response here)

2) *Which, if any, of the concepts or details discussed in this section are unclear or confusing? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

3) *What gaps or disconnects may exist in this section? What should be added or clarified in the ISO rules to address this?*

   (insert response here)

4) *In addition to 2) and 3) above, what other factors or information should the AESO consider as it drafts the ISO rules for this section?*

   (insert response here)

SPECIFIC FEEDBACK QUESTION

1) *What additional considerations or further detail may be required regarding the determination of the asset-specific reference price for non-thermal, energy-limited assets?*

TCE supports the increase of the asset-specific reference price from 2 x SRMC to 3 x SRMC in cases where the supply cushion is 1,000 MW or greater. TCE also supports the AESO's proposal that scarcity pricing be initiated when the supply cushion drops below 1,000 MW as this roughly coincides with the size of the two largest contingencies (i.e., an N-2 condition).

TCE also supports a graduated scarcity mechanism that is applied when the supply cushion is less than 1,000 MW and above the no-look threshold. TCE is, however, somewhat concerned with the proposed reference price since, during scarcity conditions, offers are generally not a function of short-run marginal cost. At this level of scarcity, it would be more appropriate for the reference price to be set at $300/MWh, which is roughly the level at which price-responsive load has turned off. In the event short-run marginal cost may exceed this level, TCE recommends the reference price be set at the higher of $300/MWh and 6 x SRMC.

TCE is supportive of the addition of a no-look threshold, below which the market power mitigation screen will not be run. However, TCE is concerned with the 250 MW level given that scarcity becomes acute when the supply cushion drops below the size of the single largest contingency (N-1 condition), which is approximately 500 MW. TCE agrees with the AESO's prior statements that the no look threshold should be tied to the single largest contingency on the system. The AESO's most recent proposal is not consistent with this concept and provides little or no support for the threshold to be set at 250 MW of supply cushion. TCE recommend the no-look threshold be reset at 500 MW to correspond with the size of the single largest contingency.

TCE recommendations are as follows:

Supply Cushion	**Reference Price**
supply cushion ≥1,000 MW	greater of $25/MWh and 3 x SRMC
1,000 MW > supply cushion ≥ 500 MW	greater of $300/MWh and 6 x SRMC
500 MW > supply cushion	No mitigation

Lastly, TCE continues to note that ex-ante mitigation is not the only available measure. Given that ex-poste mitigation will continue to exist, TCE suggests that the AESO can have a less stringent ex-ante mitigation tool. TCE submits that it is better to rely on ex-poste mitigation to some extent than to over mitigate the market on an ex-ante basis

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ADDITIONAL COMMENTS

Please add any additional comments you may have on this section here.

(insert response here)

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