September 27, 2018

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Attn: Tom Chapman, Senior Manager, Market Development, NERSC

Re: IESO Non-Emitting Resource Subcommittee (NERSC) Webinar September 21, 2018 Feedback on the Modelling Ontario's Electricity Markets Exercise

Dear Tom,

On behalf of TransCanada, thank you for the invitation and the opportunity to participate in the NERSC webinar on September 21st, 2018. We appreciate the opportunity to provide input into this important forum and we look forward to seeing the results on October 10.

In addition to our comments during the webinar we provide the following in the spirit of constructively improving the results of the consultant's modelling exercise.

TransCanada believes that the assumptions for the consultant's modelling should be consistent with the most recent IESO data and current design being discussed by the Market Renewal Working Group.

We would recommend the IESO consider utilizing the most recent Ontario load forecasts as presented by the IESO at the Technical Planning Conference on September 13 as opposed to the 2016 Ontario Planning Outlook data (slide 20).

We would recommend that the consultant should model the Capacity Market based on the design currently being discussed by the MRP and consistent with the current IESO view that Capacity needs are expected to be met without the need for significant new build generation, and that existing generation will continue to participate as capacity at a cost as reflected in the 2017 study "The Future of Ontario's Electricity Market - A Benefits Case Assessment of the Market Renewal Project" (Slide 15).

We would recommend that the level of Capacity Imports from adjacent systems be modelled from the results of a Multi Area Reliability Simulation (MARS) Multi Area rather than historical energy import data at times of peak demand. The 1900 MW assumed is very likely higher than what can be reliably depended on in time of need (Slide15).

We would also recommend that the reserve margin used to set the demand curve currently assumed to be 15% be modelled at the reserve margins assumed by the IESO in the recent Technical Planning Conference (Slide 15).

We would also like the IESO's consultant to consider adding pumped storage to the model and utilize the following new resource capital and fixed cost assumptions (Slide 22):

Type	Fixed O&M ($/kW-yr, $kWh-yr for Storage)	Capital Cost ($/kW, $kWh for Storage)	Economic Lifespan (years)	Levelized Capital Cost ($/kW-yr, $/kWh-yr for storage)	Capital Recovery Factor
Pumped Storage Hydro (8-hour)	$20/kW-yr ($2.5/kWh-yr)	$2,500/kW ($312/kWh)	40-100	$230/kW-yr ($29/kWh-yr)	7.8%

We note that pumped storage can be added in durations of less than 8 hours at lower investment costs than stated above.

We recommend that the IESO should take this opportunity to ascertain the total amount of variable wind, solar and hydroelectric that is surplus to system needs and subject to economic curtailment. We believe that the current SBG forecasts may be net of the economic curtailment that has already taken place (slide 9).

We believe that it is important to model storage resources using a consistent set of assumptions. Your chart on the right side of Slide 13 indicates that the capacity value of storage is a function of hours of storage and the level of storage penetration relative to peak load. It is unclear in the economic inputs chart on Slide 22 what duration of storage has been assumed. Many US FERC regulated jurisdictions require 4 hours of storage to be considered capacity. The IESO has indicated that there are 1400 MW of btm storage by ICI participants and 174 of pumped storage for a total of 1574 MW or 6.5% of the peak demand. We expect this figure overstates the actual capacity value of these resources.

Also on slide 22, there is a footnote indicating that the modelling assumes uprates of 3.5% of existing supply capacity will be available in the future at a $22-$27/kW-yr based on the experience of PJM's 2009/10 and 2010/11 third incremental auctions, in which uprates likely set prices (Second Performance Assessment of the PJM RPM). In the Ontario context, due to the very different supply mix, we believe uprates will be principally limited to the natural gas fired generating resources. We suggest a reasonable upgrade view is 3.5% of the existing natural gas fleet or ~300 MW.

We thank the IESO for the opportunity to participate in the NERSC process and we look forward to reviewing results in October. Should you have any questions about this letter, please do not hesitate to contact us.

Sincerely,

John Mikkelsen, P. Eng.,
Director, Power Business Development, TransCanada

cc: Margaret Kuntz, TransCanada