HYDRO ONE NETWORKS INC.'S
JRAP (2023-2027) APPLICATION (EB-2021-0110)
VECC'S TECHNICAL CONFERENCE QUESTIONS
<u>PANEL 3 – RATES AND CUSTOM IR</u>

REGULATORY ACCOUNTS

VECC TCQ-1

REFERENCE: Exhibit G, Tab 1, Schedule 1, Attachment 3, page 2
Exhibit D, Tab 4, Schedule 1, page 5 (Table 2)
Exhibit I, Tab 24 Schedule G-VECC 90 – Attachment 1

PREAMBLE: The following is an extract from VECC 90 – Attachment 1, 2019 EE Variance Tab:

STEP 2: Total "verfiied" Savings (EE+C&S)

		2016	2017	2018	2019	Data Source
(3)	EE and C&S	2,512	2,598	2,562	2,532	2006-2017 Tally Persistence tabl
(1)	2018 EE program			173	173	2018 IESO program evaluation report
(2)	2019 EE program				60	2019 IESO program evaluation report

The table of "IESO 2006-2017 Savings & Pesistence Table" has been response to VECC-24 part (d) in EB-2019-0082,

a) According to VECC 90, Attachment 1 the source of the data used for the verified 2016 and 2017 EE and C&S savings is the response to VECC 24 part (d) from EB-2019-0082. However, after downloading the file from the OEB's web site, VECC discovered that both the net energy and the net demand savings reported for 2015 and after are not accessible due to an apparent error in the references used in the spread sheet. Please provide a "readable" version of the file and confirm that the values used in VECC 90 are the total net demand saving as set out in columns FH through FK of the VECC 24 d) attachment.

b) In Exhibit D, Tab 4, Schedule 1, page 5 (Table 2) Hydro One Networks sets out the CDM impact on system peak demand for 2006-2027.

   i. Please confirm that the values for the years 2016 through 2018 are the same as those used in the EB-2016-0160 application {Exhibit E1/Tab 3/Schedule 1, page 8}.

   ii. Please explain why, in the current application, Hydro One Networks did not use the verified values for 2016, 2017 and 2018 as established for purposes of the LDC CDM and Demand Response Variance Account?

c) In Table 2 from Exhibit D, Tab 5, Schedule 1 the 2019 CDM savings are 2,511 MW at the point of Generation. This value is materially less than the verified 2019 savings used in the Variance Account calculation (2,766 MW at the point of end-use). Why weren't the verified savings for 2019 used in the current Application?

LOAD FORECAST – TRANSMISSION

VECC TCQ-2

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 40 f) & h)
Exhibit I, Tab 24, Schedule D-VECC 41 d) & h)

a) With respect to VECC 40 f), please explain why Hydro One cannot provide a "predicted" value for last calendar year for which 12 months of actual historical data is available based on the Monthly Econometric Model. If Hydro One can provide predicted values for subsequent years based on forecast values for the Monthly Econometric Model's explanatory variables, why can't the actual values for the explanatory variables be used to produce a predicted value for a past year?

b) VECC 40 h) confirms that the Monthly Econometric Model is based on energy at point of generation while VECC 41 h) confirms that the Annual Econometric Model is based on point of use by the customer. What is the loss factor used to convert energy at point of use to energy at point of generation?

c) VECC 41 d) explicitly asked about how the Annual Econometric Model accounted for embedded behind the meter generation. Was the response provided meant to be applicable to embedded generation behind the customer's meter?

VECC TCQ-3

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 42 b) & e)

a) With respect to VECC 42 b), please explain why it was not necessary to add CDM back into the actual values for the End Use model and why the forecast is gross of incremental CDM over the forecast period

b) With respect to VECC 42 e), please explain why predicted values using the End Use model are not available "for the base year (2020) due to the nature of the End-use model".

VECC TCQ-4

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 43 c)

PREAMBLE: VECC 43 c) sets out the annual energy growth rates produced by each models and the annual energy growth rates used by Hydro One in in developing the Transmission load forecast.

a) Are the 2021 growth rates for each of the three models based on comparing the model's forecast for 2021 with the actual (weather normal) use in 2020?

b) The response to VECC 43 c) indicates that the growth rates are "gross of the load impact of CDM and Embedded Generation when applicable". Does this mean that:

i) For the Monthly Model the growth rates are gross of CDM and Embedded Generation, but

ii) For the Annual Model and the End Use Model the growth rates are gross of CDM but not Embedded Generation?

If not, what does it mean?

c) The response to VECC 43 c) states:

> "The growth rates used in the proposed forecast are higher compared to the average forecast growth rate implied by the forecasting model in view of other considerations including developments in Leamington and surrounding areas and to account for potential additional load growth due to other factors (e.g., EVs) that could materialize."

  i. What impact from the Leamington developments was factored into the 12 month average system peak forecast for 2021 to 2027?
  ii. What incremental impact was attributed to electric vehicles for the years after 2020?
  iii. What other considerations led to adopting a higher load forecast?

VECC TCQ-5

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 40 b) & c)
Exhibit I, Tab 24, Schedule D-VECC 57 c), Attachment 1

PREAMBLE: VECC 40 b) sets out the annual historic CDM energy savings added back for purposes of the Monthly Energy model.

VECC 40 c) refers to VECC 57 c) for the source of values and VECC 57 c) indicates that, for the period 2006-2018, the source of these values is the 2018 OPO. VECC 57 c), Attachment 1 (Figure 19) provides the actual values as copied below:

Long Term Conservation Forecast													
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3	7.0
Existing program savings and persistence (2006-2018)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0	11.3
Savings from future energy efficiency initiatives (2019 onward)													
	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3	18.4

a) Please confirm that the 2018 OPO was produced by the IESO and whether the values are based on point of generation or point of use.

b) Please explain why the values provided in VECC 57 c), Attachment 1 (Figure 19) differ from those in VECC 40 b).

VECC TCQ-6

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 57 c)

a) VECC 57 c) indicates that the source of the Ontario CDM energy savings for 2019-2021 is from the IESO and refers to VECC 92 Attachment 1 as the source. However, the Attachment to VECC 92 deals solely with the MW savings attributable to ICI for 2016 to 2019 and has no energy savings data.

i. Please provide the source of the CDM energy savings values used for 2019-2021.

ii. As part of the response, please demonstrate that the energy savings for 2019-2020 are consistent with the 1.4 TWh of savings the IESO's Interim CDM Framework targeted for that period.

VECC TCQ-7

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 38 b)

a) Under Step 1 there are two tables. The first is described as: "The EE peak savings for 2019-2027 is provided by the IESO in Feb 2021". The second is described as "The EE summer peak savings for 2019-2027 is provided by the IESO in Feb 2021". As the transmission system peaks occur in the summer, why do the MWs of EE savings differ between the two tables – for example for 2019 the first table shows 2022 MW while the second shows 2511 MW?

b) Why are the values from the second table used in the Application?

LOAD FORECAST - DISTRIBUTION

VECC TCQ-8

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 46 c)

a) VECC 46 c) asked for the June and July 2021 customer counts by class and an indication of the Seasonal class' breakdown between UR, R1 and R2. The response stated: "The requested information is not readily available." Does this response apply to both requests (i.e., the counts for the existing classes and the Seasonal breakdown)?

b) If yes, please explain why the actual customer counts by class are not available, as other LDCs frequently provide year to date customer counts in response to similar queries made during the review of their COS rate applications.

VECC TCQ-9

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 47, Attachment 1
Exhibit I, Tab 24, Schedule L-VECC 109

a) In VECC 47, Attachment 1the forecast for the total number of Residential/Seasonal customers is based on the annual change in the number of Ontario households and then this total is broken down into the separate classes. The Attachment provides the percentage breakdown for each year by class but does not indicate how the percentages were derived. Please explain their derivation?

b) Also, VECC 47, Attachment 1 adjusts the individual Residential and Seasonal class customer counts for "reclassification" (see rows 24-31). Are the reclassification adjustments shown for 2021 and 2022 the result of the density review done in the later part of 2020?

c) VECC 109 b) sets out the reclassification that occurred as a result of the density review done in Q4 of 2020. However, the adjustments shown in Attachment 1 of VECC 47 don't match the customer movement set out in VECC 109 b). For example, for R1 VECC 47 shows a net decrease of 1,108. However, the adjustments described in VECC 109 result in a net decrease of 2,124. Please reconcile and indicate if the customer class count forecasts used in the Application need to be revised.

d) According to Exhibit L, Tab 1, Schedule 2, page 2 density boundary reviews are undertaken annually and according to VECC 109 a) the boundary review used for the 2018 rate application (EB-2017-0049) was completed in November 2016. The response to VECC 109 b) suggests that the only time customers have been reclassified as a result of subsequent density-based rate class boundary reviews was for the 2020 review.
    i. Please confirm that annual reviews were undertaken in 2017, 2018 and 2019.
    ii. Please confirm that there were no boundary adjustments/customer reclassifications as a result of these reviews?

e) VECC 109 d) states that the most recent boundary review was completed in 2020. Was there no boundary review done in 2021? If not, why not?

VECC TCQ-10

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 52 a)

a) VECC 52 a), parts ii), iii) and iv) requested the predicted 2020 Retail energy (before deducting CDM) based on the Monthly Econometric Model, the Annual Econometric Model and the End Use Model respectively. In response to part (ii) the same 2020 value was provided (21,323 GWh) for each of the models. Please confirm that this is the actual Retail Energy for 2020 (before deducting CDM).

b) The response to VECC 52 a) part (iii) provides the predicted 2020 Retail energy (before deducting CDM) based on the Annual Econometric Model. Please provide the predicted 2020 Retail Energy based on the Monthly Econometric Model – per the original interrogatory request.

c) Does the same explanation (as provided in response to VECC TCQ 3) as to why predicted 2020 value for transmission load is not available based on the Transmission End Use Model apply for the Distribution End Use Model?

VECC TCQ-11

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 52 c)

a) Are the 2021 growth rates set out in VECC 52 c) based on the difference between each Model's predicted value for 2021 and the actual value for 2020?

b) The response to VECC 52 c) indicates that in developing the proposed Distribution load forecast Hydro One Networks looked at the GWH forecast from each of the models and, in considering other factors such as EV development, electrification and what you've characterized as "the future state of the economy in an evolving situation", proposed a higher forecast than suggested by the various models. Please provide more details on how the proposed forecast was determined in terms of the incremental impacts attributed to various factors considered.

VECC TCQ-12

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 53, Attachment 1

a) VECC 53, Attachment 1 sets out the factors used to allocate the total delivered sales to the individual customer classes and how they change over time. Please explain how the factors for each year were established?

b) In determining the sales by customer classes, Attachment 1 makes adjustment for the elimination of the Seasonal class and the change in eligibility for the ST class. However, there are no adjustments made for the impact of the density-based boundary review done late in 2020. Please explain why.

VECC TCQ-13

REFERENCE: Exhibit I, Tab 24, Schedule D-VECC 57 c)

a) VECC 57 c) states that the HON- Distribution's CDM savings are "based on the total savings for Ontario". Please explain how HON-Distribution's CDM savings were derived from the total savings for Ontario and provide any supporting references.

b) For the years 2006-2018 the source used for the total Ontario energy savings is the 2018 OPO. However, the reference used to source actual savings for purposes of the Transmission CDM variance account (EB-2019-0082 – response to VECC 24 d)) also includes verified Ontario energy savings for the period 2006-2017 and the numbers differ from those in the 2018 OPO. Why weren't the verified actual results used?

COST ALLOCATION - TRANSMISISON

VECC TCQ-14

REFERENCE: Exhibit I, Tab 24, Schedule H-VECC 96 b) and VECC 100

a) VECC 96 b) briefly describes the change in methodology for determining the Line Connection portion of Dual Function lines. In order to better understand the change, please provide a simple (illustrative) example.

b) The response to VECC 96 b) i) states that the change results in costs being shifted from the Network Pool to the Line Connection Pool. However, in VECC 100 b) for those lines where the change in allocation is attributed to this correction in methodology, in 7 out of the 8 instances, the percentage of costs allocated to the Network Pool are now higher. Please reconcile these results with the response to VECC 96?

COST ALLOCATION DISTRIBUTION

VECC TCQ-15

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 107 a)

a) The preamble to VECC 107 includes an extract from the current 2021 tariff sheet which states that one of the requirements for ST eligibility is that the customer's load is connected at between 13.8 and 44 kV. Does this mean that eligible customers must be taking power at voltages between 13.8 and 44 kV? If not, what it the requirement?

b) Please confirm that the proposed eligibility criteria for ST contain the same provision.
    i. If confirmed, please reconcile with the fact that the proposed change in eligibility means that ST customers using an HON transformer can be taking power at 347/600 volts (per VECC 107 a), Table 1).

c) Will these newly eligible ST customers being served by a HON transformer be required to own the lines on the secondary side of the transformer or, in some instances, could HON own these lines?

VECC TCQ-16

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 107 b)

PREAMBLE: VECC 107 b) discusses the practices of other large distributors with respect to providing utility owned transformers. The response indicates that Alectra and Ottawa Hydro will own 27.6kV-347/600V service transformers up to 3000 kVA and 2500 kVA, respectively. It also indicates that it is also Hydro One's understanding Toronto Hydro will own 27.6kV-347/600V service transformers up to 2500 kVA.

a) In such circumstances are the Alectra, Ottawa Hydro and Toronto Hydro customers with loads peak demands between 500 kW to 3,000 kW treated as General Service customers?

b) Does HON currently have customers in its GS classes with loads in the 500 kW to 3,000 kW range that will continue to be classified as such even with this change in eligibility for ST?

c) If yes, why wouldn't offering to provide HON transformers of up to 3,000 kVA to customers in the GS class be a more appropriate way of addressing the issue?

VECC TCQ-17

REFERENCE: Exhibit I, Tab 1, Schedule L-Staff 322 c)

a) Staff 322 c) asked for "a cost allocation scenario where both the costs associated with the transformers used by the ST rate class, and the revenues associated with the ST transformers are allocated to the ST rate class". The response indicated that this was inappropriate because the CAM would use the total ST class demand data to allocate a portion of the line transformer cost to the ST rate class when most of the class uses their own transformers. Cannot this problem be readily resolved in the same way it is for the allocation of transformer (USOA 1850) costs to other classes such as the various GSd classes where the customer count allocators and demand allocators for transformers are based not on the total customer count and demand for the class but rather on the customer count and demand associated with the HON transformers?

i. If yes, please provide the requested cost allocation scenario.
ii. If not, why not?

VECC TCQ-18

REFERENCE: Exhibit I, Tab 1, Schedule L-Staff 323
Exhibit I, Tab 24, Schedule L-VECC 120
Exhibit L, Tab 1, Schedule 3, page 4
Exhibit L, Tab 1, Schedule 3, Attachment 2, page 3.

a) Staff 323 indicates that the load profiles for customer classes were based on one year of hourly data and that an additional year's data was available as backup.

   i. What year's data was used to develop the load profiles?

   ii. If it was 2020, are the calculated load profiles impacted by the pandemic?

   iii. What was the year for which the "additional year's data" is available.

b) Please re-calculate the 2023 demand allocators using the average of the two years' results?

c) VECC 120 c) sets out the 12 CP values assuming the seasonal class is not eliminated.

   a. Please confirm that the total for the various Residential classes and the Seasonal class is 26,548,689.

   b. Are the 12 CP values in VECC 120 c) in meant to be the Transformation, Delivery or Bulk System 12 CP values?

d) Exhibit L, Tab 1, Schedule 3, Attachment 2, page 3 sets out the 12 CP allocators used in the 2023 Cost Allocation model – in which the Seasonal class is eliminated. It is noted that the sum of the 12 CP values for the Residential classes does not equal 26,548,689 regardless of which definition of 12 CP is used. Please explain why when the Application states (Exhibit L, Tab 1, Schedule 3, page 4) the overall 12 CP remains the same before and after seasonal elimination.

VECC TCQ-19

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 134

PREAMBLE: The response to VECC 134 a) indicates where/how the GFA, NFA and Depreciation Direct Allocation Factors are incorporated into the 2023 Cost Allocation Model for purposes of allocating costs to the six acquired utility rate classes. A review of the references indicates that for each acquired customer class a single GFA adjustment factor is calculated based on the overall difference between the values of the 1815-1860 assets costs allocated in the 2023 CAM and versus those directly tracked and then allocated based on historic CAM results.

a) VECC 134 d) asked for the GFA adjustment factor for each USOA and the results vary widely. Would the 2023 CAM results be different if the specific GFA adjustment factors had been used for each USOA account?

   i. If yes, please provide a Cost Allocation scenario that demonstrates how material the difference is.

   ii. If not, why not and please provide a Cost Allocation scenario that demonstrates this would be the case.

VECC TCQ-20

REFERENCE: Exhibit L, Tab 3, Schedule 1, pages 10-11
Exhibit I, Tab 24, Schedule L-VECC 138 b)

PREAMBLE: Exhibit L, Tab 3, Schedule 1, page 10 sets out the calculation of the upper and lower "goalposts" for the combined former Haldimand/Norfolk and the former Woodstock acquired customer classes. The evidence also states (page 11) that as long as the revenues collected from the former customers of the acquired utilities fall within these goal posts both the acquired customers and HON's legacy customers are better off as a result of the acquisition.

a) For Woodstock, the goal posts are roughly \$7.0 M and \$9.3 M and that the proposed revenue to be recovered from customers of the former Woodstock utility in 2023 is \$8.5 M – which falls between these two values. However, the 2023 R/C ratios for the Acquired Urban Classes are 0.94, 0.80 and 0.80 for the Residential, General Service<50 and GS>50 classes respectively (per Exhibit L, Tab 2, Schedule 1, page 7)and the costs allocated to the customers of the former Woodstock utility total \$9.5 M ((per VECC 138 b). Would it be correct to conclude that if the revenue to cost ratios for the Acquired Urban classes were to be increased to 100% then the resulting revenues would exceed the upper goal post of \$9.3M? If not, why not?

b) Does this result have any implications for the appropriate policy range for the R/C ratios for the Acquired Urban Utility classes. In particular, should the upper end of the policy range for these classes be set at 98% (i.e., the value that results from dividing the upper goal post by the allocated costs)? If not, why not?

c) VECC 138 b) indicates that the costs allocated to the former Haldimand/Norfolk customer classes are approximately $28.6 M. Comparing this to the upper goal post for this group of $32.9 M, the resulting ratio is 115%. Similarly, comparing the lower goal post for this group ($23.9 M) to the allocated costs yields a ratio of roughly 84%. Do these results suggest that the R/C ratio range applicable to the GS customer classes in this group should be narrower than the standard 80% to 120%? If not, why not?

RATE DESIGN – DISTRIBUTION

VECC TCQ-21

REFERENCE: Exhibit L, Tab 2, Schedule 1, pages 5-7 and Attachment 1
Exhibit I, Tab 24, Schedule L-VECC 123

a) Please confirm that in calculating the status quo Revenue to Cost Ratios for the years after 2023 the Application, when determining the "revenues" to be used, takes into account year over year changes in the billing determinants for each customer class (per Step 4 as described on page 5) and thereby addresses that fact (per VECC 123) that the "the billing determinants for the various rate classes (i.e., customer/connection counts, kWh values and kW values) do not all change by the same percentage for each year during the 2024-2027 period".

b) Please confirm that in calculating the status quo Revenue to Cost Ratios for the years after 2023 the Application, when determining the "costs" to be used, simply increases each customer class' allocated costs from the previous year by the same percentage and, in doing so, does not account for the fact that the customer and demand allocators for the various rate classes may all not change by the same percentage for each year during the 2024-2027 period.

VECC TCQ-22

REFERENCE: Exhibit L, Tab 2, Schedule 1, page 11

a) With respect to the design of Hydro One's distribution rates, please clarify whether your proposal to maintain the current fixed variable split for all of the non-residential classes (per L/1/2, page 11) means that for each of the test years:
   i. The percentage split between fixed and variable revenues is the same as calculated for 2022 based on the rates and billing determinants for 2022, or
   ii. The percentage is based on relative fixed and variable revenues as calculated using the previous year's rates and the forecast billing determinants for test year.

b) Is the approach used by Hydro One consistent with the OEB's June 2021 Chapter 2 Filing Guidelines which at page 54 state:

"Calculations of fixed/variable proportions should use the billing determinants from the proposed load forecast as the basis of the calculation."

VECC TCQ-23

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 124

a) The response to VECC124 references the $8.38 change in fixed charges based on a 7-year phase-in cited in the Board Staff's EB-2015-0079 submissions. However, in its Decision the Board rejected the 7 year phase-in in favour of 8 years. Please indicate what the increase in the fixed charge was for 2016 based on the eight year transition approved by the Board.

VECC TCQ-24

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 107
Exhibit L, Tab 2, Schedule 1, page 20 (Table 11)

a) The response to VECC 107 indicates that the number of transformers HON will own that serve ST customers will increase from by 5 per annum going from 24 to 49 by the end of 2027. Exhibit L, Tab 2, Schedule 1, Table 11assumed an average of 51 ST customers with HON transformers over the period up to 2032 in deriving the $200 charge. Can you confirm that this is based on the assumption that the number of customers will continue to increase by 5/year up to 2032?

b) Please confirm that, by using a simple average of 51 customers, the ST rate calculation does not account for the fact there are fewer customers in the earlier years when, on a net present value basis, the revenues are "worth" more.

c) Please provide: i) the annual 2023-2032 revenue requirement values associated with the $1.2 M total (per Table 11) and ii) what the annual charge would be such that, using HON's cost of capital, the total NPV of the revenue from the charge equals the total NPV of the annual revenue requirements.

VECC TCQ-25

REFERENCE: Exhibit I, Tab 24, Schedule L-VECC 126 a) & 127 c)
Exhibit L, Tab 1, Schedule 3, Attachment 1 (2023 CAM), Tab I3 (TB Data-Account 5160)

PREAMBLE: VECC 126 a) indicates that the capital costs for transformers that will be used by the ST customers are recorded in USOA 1850. The maintenance costs for these transformers is recorded in USOA 5160 and that based on the cost breakout in the CAM model the amount for 2023 is just under $3 M. ($2,966,867).

a) The response to VECC 127 c) states that "only visual inspection costs were included in the annual OM&A calculations. Service transformers are replaced on failure". Is the $3 M included in Account 5160 for 2023 all for visual inspections?

VECC TCQ-26

REFERENCE: EB-2020-0246 – OEB Decision re: Elimination of Seasonal Rates

PREAMBLE: On November 10, 2021 the OEB issued its Decision regarding the elimination of Seasonal Rates and with respect to mitigation for Seasonal moving to R2 determined that Phase-In option 2 A should be adopted whereby bill impacts are limited to 10% for low volume (50 kWh/month) Seasonal customers.

a) In the Application Hydro One Networks set out the bill impacts by customer class for each of the years 2023-2027 (L/6/1). For those Seasonal customers moving to the R2 class the evidence did not include any proposals regarding bill impact mitigation – pending the Board's decision on the Elimination of the Seasonal class. The Board has now issued its decision (EB-2020-0246) regarding the elimination of the Seasonal class and the bill impact mitigation approach that's to be used for Seasonal customers moving to the R2 class. Based on this Decision, please provide the revised rates for each of the year 2023-2027 that will apply to Seasonal customer moving to the R2 class and for each year also provide bill the impact calculations based on the average monthly use for these customers and for 50 kWh/month usage.

b) In its EB-2020-0246 Decision the Board directed Hydro One to maintain existing billing and meter reading frequencies for seasonal customers. Given this Decision are there any incremental implementation costs for billing and metering due to the elimination of the Seasonal class and, if yes, what are they?

c) Will there be other implementation costs associated with the Decision and, if yes, please provide an estimate as to what these will be?

d) If there are incremental costs, is it still HON's intent to apply for a deferral account to capture these costs?

e) During the Seasonal Elimination proceeding HON indicated it would need an exemption from the DSC to continue its current meter reading and billing practices for former Seasonal customers and would apply for a deferral account at the same time as it applied for the DSC exemption. Is that still Hydro One Networks plan and, if yes, when does Hydro One Networks anticipate applying for the DSC exemption?